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PUBLIC UTILITIES COMMISSION

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

In the Matter of the Application of HAWAIIAN ELECTRIC COMPANY, INC. Approval of Rates Increase and Revised Rate Schedules and Rules.	)	DOCKET NO. 2008-0083

DIVISION OF CONSUMER ADVOCACY'S SUPPLEMENTAL TESTIMONIES AND EXHIBITS

Pursuant to the Interim Decision and Order filed on July 2, 2009, the Division of Consumer Advocacy submits its **SUPPLEMENTAL TESTIMONIES AND EXHIBITS** in the above docketed matter.

DATED: Honolulu, Hawaii, July 20, 2009.

Respectfully submitted,

By Cath P. Awak
CATHERINE P. AWAKUNI
Executive Director

DIVISION OF CONSUMER ADVOCACY

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ST-1

M. BROSCH

SUPPLEMENTAL TESTIMONY

OF

MICHAEL L. BROSCH

ON BEHALF OF
THE DIVISION OF CONSUMER ADVOCACY

SUBJECT: **HECO Revised Interim Increase, IRP/DSM Costs, Management Audits.**

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Q. PLEASE STATE YOUR NAME.

A. My name is Michael L. Brosch.

Q HAVE YOU SUBMITTED TESTIMONY IN THE INSTANT PROCEEDING ON BEHALF OF THE DIVISION OF CONSUMER ADVOCACY, HEREINAFTER REFERRED TO AS CONSUMER ADVOCATE?

A. Yes. I previously submitted testimony designated as CA-T-1 and CA-T-5 in this proceeding, addressing revenue requirements and cost of service/rate design, respectively. My qualifications are summarized in CA-100 which was previously filed with the CA-T-1 testimony.

Q, WHAT IS THE PURPOSE OF THE SUPPLEMENTAL TESTIMONY THAT YOU ARE NOW SPONSORING?

A. This supplemental testimony will address several specific matters that were raised by the Commission in its Interim Decision and Order ("ID&O") filed on July 2, 2009 in this Docket. In particular, this testimony is responsive to:

- Part II of the ID&O directing HECO to make certain changes to its Probable Entitlement calculations.
- Part III (e) regarding IRP/DSM costs and transition of energy efficiency programs to a third-party administrator, and
- Part III (i) regarding possible management audit work.

I. <u>REVISED HECO PROBABLE ENTITLEMENTS CALCULATIONS.</u>

Q. WHAT CONCERNS WERE RAISED BY THE COMMISSION IN PART II OF THE ID&O?

A. This section of the ID&O lists a series of Hawaii Clean Energy Initiative ("HCEI") provisions and costs that have not received Commission approval or that have otherwise not been supported at this time, and that should therefore be removed from the calculated probable entitlement amount supportive of an interim rate increase. These include:

- Sales decoupling and the Revenue Balancing Account
- HCEI-related employee positions
- HCEI-related outside service costs
- Campbell Industrial Park Combustion Turbine Unit ("CIP CT-1")
- Employee Electricity Rate Discount (foregone revenues)
- Merit Employee Wage Increases
- Reduced Current Commodity Prices

To address these changes, HECO filed on July 8, 2009 its revised calculations supportive of a lower $61.1 million interim rate increase, representing a reduction of approximately $18.7 million from the $79.8 million interim increase that HECO had proposed in its May 18, 2009 Statement of Probable Entitlement submission. Mr. Steven Carver (CA-ST-3), Mr. Joseph Herz (CA-ST-2) and I reviewed the detailed calculations supporting the Company's revisions to this previous Statement of Probable Entitlement and discussed the changes made with HECO and DOD representatives. On July 15, 2009, the Consumer Advocate filed a letter with the Commission commenting on HECO's revised calculations, which concluded that the revised calculations appeared to generally comply with the ID&O and was conservatively prepared.[1] This section of my testimony describes several of the changes ordered by the Commission and supports the Consumer Advocate's conclusion that the Company's revisions were conservatively prepared and in compliance with the direction provided in the Commission's Interim Decision and Order.[2]

Q. WERE ANY CHANGES REQUIRED TO THE HECO STATEMENT OF PROBABLE ENTITLEMENT TO REMOVE ANY EFFECTS ASSOCIATED WTIH DECOUPLING OR THE PROPOSED REVENUE BALANCING ACCOUNT ("RBA")?

A. No. Implementation of decoupling and the proposed RBA accounting procedures are entirely prospective in nature and have no impact upon the HECO revenue requirement in this rate case. If decoupling were not approved

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1 When the Consumer Advocate has made reference to "conservative" estimates used in complying with the ID&O, the Consumer Advocate's use of this term is generally consistent with HECO's use in its July 8, 2009 filing. That is, HECO's adjustments reflect amounts that have generally excluded more, rather than less, of the expenses and expenditures from the revenue requirement calculation.

2 Mr. Carver describes in CA-ST-3 one area where certain R&D projects not removed from HECO's revised revenue requirement may be considered HCEI related.

by the Commission, the revenue requirement would be unchanged, because the lower sales forecast submitted with the Company's December 2008 rate case updates was adopted in calculated the Stipulated Settlement rate increase amount.[3]

Q. DID HECO MAKE THE NEEDED ADJUSTMENTS TO REMOVE HCEI RELATED EMPLOYEE POSITIONS AND OUTSIDE SERVICE COSTS FROM ITS INTERIM RATE INCREASE CALCULATIONS?

A. Yes. Mr. Carver discusses these revisions in more detail in CA-ST-3.[4]

Q. HAS HECO PROPOSED ANY REVISIONS TO THE INTERIM RATE INCREASE TO REMOVE THE COSTS FOR CIP CT-1?

A. Yes. Mr. Carver reviewed the rate base adjustments that were made by HECO. I reviewed and concur in the reductions to Operation and Maintenance Expenses that were made to HECO to eliminate the amounts included in the test year for CIP CT-1.

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3 HECO had proposed in its rate case updates HECO T-1 that the lower sales forecast could be ignored for ratemaking purposes if the RBA process were approved by the Commission. This proposal was not accepted by the Consumer Advocate, as more fully explained in CA-T-1 at pages 39-43.

4 The only possible exception regarding HCEI costs relates to certain R&D projects, as more fully explained in CA-ST-3.

Q. HOW DO HECO EMPLOYEE ELECTRIC RATE DISCOUNTS IMPACT THE REVENUE REQUIREMENT?

A. HECO employees receive an electric rate discount pursuant to Rate Schedule E, which charges employees 2/3 of the current effective Schedule R residential rates for the first 825 KWH used by the employee during the month. Employees are charged the full Schedule R rate for any usage above 825 KWH per month.[5] When the rate case filing is prepared, calculations are performed to estimate the foregone revenue associated with discounted service to employees.

Q. IN PREPARING ITS JULY 8 REVISED SCHEDULES RESULTING FROM INTERIM DECISION AND ORDER, DID HECO FULLY REMOVE THE NEGATIVE REVENUE ADJUSTMENT ASSOCIATED WITH EMPLOYEE DISCOUNTS UNDER RATE SCHEDULE E?

A. Yes. This revision can be observed by comparing the HECO T-3 Attachment 1, page amounts on the "SCHEDULE E ADJ." and the "2007 Interim Rate Increase" lines to the corresponding lines on HECO T-3, Attachment 2. Approximately $1 million of revenue increase is attributable to elimination of the Schedule E employee discounts.

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5 See HECO-105, page 32 of 87 for the presently effective Schedule E.

Q. HAVE YOU CONDUCTED ANY STUDIES TO DETERMINE WHETHER CURRENT ECONOMIC CONDITIONS OR THE NEED TO INCENTIVIZE ENERGY CONSERVATION JUSTIFY ELIMINATION OF THE RATE DISCOUNT EMPLOYEE BENEFIT?

A. I have not. It is my understanding that this form of employee benefit has been in place for many years at the HECO. I expect that HECO will provide information to the Commission in defense of this element of employee compensation that may be useful if the Commission decides to reconsider this issue.

Q. DID HECO MAKE THE NEEDED ADJUSTMENTS TO REMOVE MERIT EMPLOYEE WAGE INCREASES FROM ITS INTERIM RATE INCREASE CALCULATIONS?

A. Yes. Mr. Carver discusses these revisions in more detail in CA-ST-3.

Q. WHAT ADJUSTMENTS WERE MADE BY HECO TO ACCOUNT FOR LOWER COMMODITY PRICES WITHIN ITS REVISED INTERIM RATE INCREASE CALCULATIONS?

A. Two adjustments are proposed by HECO to estimate how lower market prices for bulk commodities may impact the test year revenue requirement. These adjustments are described in Exhibit 3 of the Revised Schedules filed on July 8, at pages 14-20. Mr. Carver discusses the revisions made by HECO with regard to estimated T&D Material inventories in more detail in CA-ST-3.

With regard to the detailed discussion of Other Production Maintenance Costs at pages 17 to 20 of HECO's Exhibit 3, I concur with the assessment regarding the challenges cited by the Company with respect to correlating commodity market prices with projected test year expenses. The Consumer Advocate in its review of these issues in the rate case submitted numerous information requests[6] to analyze production maintenance expenses and proposed several ratemaking adjustments to such expenses, but did not attempt to revise HECO's expense projections directly from commodity price data.[7] In spite of these difficulties, as described in Exhibit 3, HECO estimated and included a downward O&M expense adjustment for commodity prices in the amount of $177,420 that appears to be a conservatively generous adjustment and that is supported by the Consumer Advocate.

II. IRP/DSM EXPENSES.

Q. THE INTERIM DECISION AND ORDER STATES, AT PAGE 15, "THERE APPEARS TO BE A SIGNIFICANT INCREASE IN IRP/DSM COSTS IN

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6 See, for example, HECO responses to CA-IR-306 through CA-IR-312, CA-IR-393 and CA-IR-470. In its response to CA-IR-393, HECO responds directly to questions raised by the Consumer Advocate about the relationship between raw material price trends and Production O&M expenses.

7 Exhibit CA-101, Schedules C-4 through C-8 impact the test year Production O&M Accounts.

THE 2009 TEST YEAR OVER PREVIOUS YEARS. THE COMMISSION IS CONCERNED ABOUT THE REASONABLENESS OF SUCH INCREASES GIVEN THE TRANSITION OF ENERGY EFFICIENCY DSM PROGRAMS TO A THIRD-PARTY ADMINISTRATOR. DID THE CONSUMER ADVOCATE HAVE THE SAME CONCERNS THAT CAUSED YOU TO PROPOSE A RATEMAKING ADJUSTMENT IN THIS AREA?

A. Yes. My testimony on this subject can be found in CA-T-1 at pages 104-113, where I expressed concern over HECO's projected DSM base expense increases that seemed inconsistent with the transfer of Energy Efficiency programs to third party administration. I proposed the ratemaking adjustment that is set forth in CA-101 at Schedule C-11 as an estimate of the savings that may be achievable by HECO prospectively as a result of the transfer. The adjustment proposed by the Consumer Advocate was in the amount of $539,000 and was based upon historical relationships between energy efficiency, load management[8] and overhead categories of expense. Additionally, the Consumer Advocate has disputed HECO's claimed need for informational advertising upon transfer of the Energy Efficiency programs to third party administration and proposed a second adjustment at CA-101,

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8 The HECO Load Management programs are not being transferred to third party administration, so HECO will retain personnel and incur costs to plan and administer these programs in the future.

Schedule C-21 that reduces advertising from HECO's proposed $1.1 million level to $342,000.

Q. WHAT IS THE STATUS OF THE TWO ADJUSTMENTS YOU JUST REFERENCED?

A. The C-11 adjustment to base DSM expenses was discussed and ultimately revised from $539,000 to $345,000 as a result of settlement discussions with HECO that are more fully described in the Stipulated Settlement Letter at Exhibit 1, pages 43 and 44. In our settlement discussions, HECO raised valid issues regarding the methodology employed by the Consumer Advocate in the Schedule C-11 adjustment, and also challenged the assumptions about office space and information technology resources that would be re-deployed upon transfer of the energy efficiency program administration role.[9]

The Consumer Advocate's advertising adjustment was not resolved in settlement and is scheduled to be considered by the Commission in hearings in this Docket.[10]

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9 Additional information on this subject can be found in HECO's responses to CA-IR-119, 121, 123, 126, 228, 231, 232, 338 and 405 through 415.

10 See Stipulated Settlement Letter, Exhibit 1, page 45.

Q. HOW WERE EXPENSES ASSOCIATED WITH INTEGRATED RESOURCE PLANNING ("IRP") ADDRESSED BY THE CONSUMER ADVOCATE?

A. In this area, there was also a concern about HECO's asserted test year expense levels. At CA-T-1 pages 113 and 114, I explained how a three year average of historical actual spending should be used to estimate these costs, rather than HECO's averaging calculation that employed projected higher expense amounts. The Consumer Advocate's adjustment is set forth in CA-101 at Schedule C-12 and is premised upon the assumption, in spite of substantial uncertainties, that the new Clean Energy Scenario Planning ("CESP") process and activities will impose activities and costs upon HECO that are comparable in amount to historical expenditures under the IRP regime.[11]

Q. WHAT IS THE STATUS OF THE CONSUMER ADVOCATE'S IRP ADJUSTMENT AT CA-101, SCHEDULE C-12?

A. This adjustment was accepted by HECO in settlement, leaving a total of $354,000 in annual expenses to fund either IRP or CESP related activities.[12]

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11 CA-T-1, page 114 and HECO responses to CA-IR-333 and CA-IR-408.

12 CA-101, Schedule C-12, line 5. See Stipulated Settlement Letter, Exhibit 1, page 51.

III. MANAGEMENT AUDITS.

Q. THE INTERIM DECISION AND ORDER AT PAGE 16 STATES, "THE PARTIES MAY FILE ADDITIONAL TESTIMONY THAT PROVIDES RECOMMENDATIONS ON THE BEST WAY TO ENGAGE IN A MANAGEMENT AUDIT TO BE PAID FOR BY HECO, OR TO SUGGEST OTHER MEANS TO ACCOMPLISH THE COMMISSION'S OBJECTIVE." DO YOU HAVE ANY RECOMMENDATIONS ON THIS MATTER?

A. Yes. I have some recommendations with regard to the process through which "management audits" may be undertaken and I also have some thoughts regarding potential HECO topics for such audits.

Q. WHAT IS YOUR EXPERIENCE WITH REGARD TO MANAGEMENT AUDITS THAT HAVE BEEN UNDERTAKEN BY REGULATORY AGENCIES?

A. My experiences have generally been negative, where many of these efforts have been focused upon vaguely defined topics associated with perceived management efficiency or inefficiency, organizational effectiveness or other business process issues. The reports resulting from studies of management effectiveness or process issues tend to identify areas of relative management strength or weakness, with recommendations aimed at improved organizational structures or business processes, rather than specific recommendations and/or adjustments that are useful in reaching regulatory decisions.

Q. HAVE SOME TYPES OF MANAGEMENT AUDITS PROVEN TO BE MORE VALUABLE TO REGULATORS?

A. Yes. From my experience, the most useful management audits are those aimed at solving specific problems that are important to the determination of just and reasonable rates. For instance, for mainland utilities involved in complex affiliated interest arrangements, studies have been conducted to find specific answers to detailed questions regarding affiliate transfer pricing, the fair market value of services provided by utility affiliates, and other matters of equity in affiliate organizations – where results were translated into ratemaking remedies for the problems that were discovered. Another example would be the very focused management audits that occurred in the 1980's to address the large cost over-runs experienced at many of the nuclear generating units brought into service in that era. These audit reports supported ratemaking recommendations regarding the prudent level of construction costs that should be allowed for rate recovery, with the author of the audit reports appearing in hearings to support such recommendations.

Q. ARE THERE SPECIFIC MATTERS THAT ARE IMPORTANT IN THE REGULATION OF HECO, AND THAT MAY MERIT SUCH A FOCUSED INVESTIGATION?

A. Yes. The first topic that comes to mind is the Customer Information System ("CIS") project. The CIS has fallen years behind schedule and HECO has asserted that its primary vendor, Peace, is in breach of contract. HECO has notified the Commission that it is evaluating a recovery plan developed with Peace to complete the installation of CIS using the Peace software, and is also reviewing its options to complete a new CIS if its contact with Peace is terminated. Deferred costs associated with the CIS project continue to accumulate and may create a very large and contentious issue in the future HECO Companies' rate cases. This situation is described in the Stipulated Settlement Letter, at Exhibit 1, pages 25 through 27, ending with the statement, "HECO agrees that the Commission should formally review the CIS cost amounts submitted for recovery by HECO after the CIS project is completed."

Other potential focused management audit topics for HECO may include the East Oahu Transmission Project or CIP CT-1, where the ultimate total costs upon completion are expected to significantly exceed initial project estimates. If there are specific operational areas of Commission concern, one possible consideration is to have a management audit focus on one operational area first. Narrowing the scope of the initial audit would serve the following purposes: 1) mitigate the possible intrusive nature of a management audit such that the Company's work processes are not disrupted on a wide-scale basis; 2) once the initial operational area management audit is complete, the results of the audit can be evaluated to help determine if changes in the procedures, scope, or other factors influencing prospective management audits are necessary; and 3) more specific and targeted audits of operational areas might lead to more effective results in terms of identifying necessary and specific regulatory actions to remedy the perceived issues. In general, the potential value of a management audit is proportional to the importance of the activities and costs being reviewed as well as expectation that answers to specific questions of interest to regulators can be answered by such an audit.

Q. ARE THERE PROCEDURAL DETAILS THAT MAY INFLUENCE THE ULTIMATE VALUE OF A MANAGEMENT AUDIT THAT IS UNDERTAKEN BY THE REGULATOR?

A. Yes. I would offer the following ideas in an effort to assure a useful work product will result from any focused management audit that may be undertaken by or for the Commission:

- The solicitation of proposals should define very clearly each of the specific questions that are to be answered and supported in the auditor's report.
- Qualifications of the auditors must incorporate all of the disciplines required to fully understand and defend the technical issues involved.
- Past and current clientele of the bidders and copies of relevant past work product must be disclosed to reveal any conflicts of interest.

- The client/auditor arrangements must be carefully defined to avoid any unintended influence upon the independence of work being performed. Thus, allowing HECO to be the client may raise issues regarding the objectivity of any result.
- Timely compensation for audit work performed should not be contingent upon the auditor's recommendations.
- The auditor should be asked to develop and present a detailed work plan prior to undertaking any discovery or interviews, for review and concurrence by the client.
- Formal procedures should be used to document all discovery and interviews, with all such documentation available for review by concerned parties in subsequent proceedings.
- The audit work product should be aimed at advocacy and fully documented evidence (including quantification of any ratemaking adjustments) supporting all recommendations, with provisions for discovery and live testimony if needed.

Q. DOES THIS CONCLUDE YOUR SUPPLEMENTAL TESTIMONY ON REVENUE REQUIREMENT AND RELATED MATTERS?

A. Yes.

ST-2

J. HERZ

CA-ST-2
DOCKET NO. 2008-0083

SUPPLEMENTAL TESTIMONY

OF

JOSEPH A. HERZ

ON BEHALF OF
THE DIVISION OF CONSUMER ADVOCACY

SUBJECT: Energy Cost Adjustment Clause Compliance with Act 162 and Reasonableness of HECO's Proposed Purchased Power Adjustment Clause

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SUPPLEMENTAL TESTIMONY OF JOSEPH A. HERZ, P.E.

I. INTRODUCTION.

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Joseph A. Herz. I am employed by Sawvel and Associates, Inc. ("Sawvel"). Sawvel is located at 100 East Main Cross Street, Suite 300, Findlay, Ohio 45840.

Q. ARE YOU THE SAME JOSEPH A. HERZ THAT PREVIOUSLY SPONSORED DIRECT TESTIMONY IN THIS PROCEEDING ON BEHALF OF THE CONSUMER ADVOCATE?

A. Yes. As described in my direct testimony, Sawvel and Associates, Inc. was retained by the Department of Commerce and Consumer Affairs, Division of Consumer Advocacy (hereinafter "Consumer Advocate" or "CA") to review and respond to that rate application filed by Hawaiian Electric Company, Inc. (hereinafter "HECO" or "Company") and to prepare direct testimony for filing with this Commission regarding the issues identified during the course of our review.

Q. ARE YOU STILL APPEARING ON BEHALF OF THE CONSUMER ADVOCATE?

A. Yes.

Q. PLEASE SUMMARIZE THE PURPOSE OF YOUR TESTIMONY.

A. On July 2, 2009, the Commission issued an Interim Decision and Order ("Interim D&O") in this proceeding. In addition to the two issues[1] that were not resolved by the parties through settlement discussions and were scheduled for hearing, the Interim D&O identified other issue areas of interest to the Commission on which the parties may file additional testimony. Generally, my supplemental testimony will address certain of those additional issues identified by the Commission, including:

1. the Commission's desire for additional testimony on whether HECO's proposed Energy Cost Adjustment Clause ("ECAC") complies with statutory requirements of Act 162, Session Laws of Hawaii 2006 ("Act 162").
2. the Commission's request for more information to determine the reasonableness of HECO's proposed Purchased Power Adjustment Clause.

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1 Return on common equity and informational advertising.

II. ECAC COMPLIANCE WITH ACT 162.

Q. HOW DOES ACT 162 AFFECT THE ECAC?

A. Act 162, in part, modified Hawaii Revised Statutes ("HRS") § 269-16 by adding a section (g), which states the following:

> Any automatic fuel rate adjustment clause requested by a public utility in an application filed with the commission shall be designed, as determined in the commission's discretion, to:
>
> (1) Fairly share the risk of fuel cost changes between the public utility and its customers;
>
> (2) Provide the public utility with sufficient incentive to reasonably manage or lower its fuel costs and encourage greater use of renewable energy;
>
> (3) Allow the public utility to mitigate the risk of sudden or frequent fuel cost changes that cannot otherwise reasonably be mitigated through other commercially available means, such as through fuel hedging contracts;
>
> (4) Preserve, to the extents reasonably possible, the public utility's financial integrity; and
>
> (5) Minimize, to the extent reasonably possible, the public utility's need to apply for frequent applications for general rate increases to account for the changes to its fuel costs.

Q. WITH RESPECT TO THE FIRST CONSIDERATION, DOES HECO'S PROPOSED ECAC "FAIRLY SHARE THE RISK OF FUEL COST CHANGES BETWEEN THE PUBLIC UTILITY AND ITS CUSTOMERS?"

A. The sharing of the risk of fuel cost changes first requires an understanding of how the ECAC handles fuel cost changes, and how the ECAC shares the risks of cost changes between the Company and its ratepayers. The Company's fuel costs are the result of: (a) prices paid by HECO for the quantity of fuel consumed in its generating plants; and (b) the quantity of fuel consumed, which is determined by the efficiency of the operation and performance of HECO's generating units to convert the fuel into electricity delivered to ratepayers. The risks of fuel cost changes are primarily associated with the fluctuations in fuel prices (item (a) above) and, to lesser extent, HECO's performance and operation of generating units (item (b) above).

HECO's proposed ECAC has fixed efficiency factors to determine the amount of HECO's fuel cost changes that are passed through to ratepayers. Essentially, the ECAC's fixed efficiency factors place on HECO, the risk of fuel cost changes due to changes in the Company's generating unit operation and performance (item (b) above). HECO bears the cost of, or benefits from, fuel cost changes due to the generation and performance of its generating units (i.e., the fuel costs associated with the actual versus fixed heat rate). Since the operation and performance of HECO's generating units are generally viewed as being within the Company's control, fuel cost changes associated with such risks are considered appropriate to be borne by the Company and its shareholders, not ratepayers. If the Company's generating system does not achieve the level of fixed efficiency in the ECAC that is set in a rate proceeding, the Company and its shareholders bear the risk and associated fuel costs of not achieving that level of efficiency. On the other hand, if HECO's generating units do better than the efficiency level in the ECAC, the

Company and its shareholders receive the benefits of such fuel cost savings. The ECAC's fixed efficiency factors are thus an effective means of sharing the operating and performance risks between HECO's ratepayers and shareholders.

With respect to the risk of fuel cost changes due to changes in fuel prices, the ECAC passes such risks in price changes through to ratepayers. Because fuel prices are not within HECO's control and HECO is a price taker, it has been considered inappropriate for HECO to bear the risks of fuel cost changes due to price changes established by a global market.

Q. ARE THERE ANY PROCESSES IN PLACE TO DETERMINE IF HECO IS ACQUIRING ITS FUEL SUPPLY AT PRICES THAT ARE REASONABLE?

A. Presently, HECO files its fuel supply contracts with the Commission for approval. This process provides the opportunity for the Consumer Advocate and the Commission to examine and evaluate whether HECO has taken appropriate actions to acquire fuel at reasonable terms and pricing. At these kinds of opportunity, issues such as contract terms, including price, can be reviewed. Other issues, such as fuel hedging might also be considered as well. The submission of fuel supply contracts for Commission review and approval is a safeguard for consumers, and provides an opportunity to mitigate the possibility that the Company might recover unreasonable fuel prices and/or price changes through the ECAC.

Q. DOES THE COMPANY'S ECAC "PROVIDE THE PUBLIC UTILITY WITH SUFFICIENT INCENTIVES TO REASONABLY MANAGE OR LOWER ITS FUEL COSTS AND ENCOURAGE GREATER USE OF RENEWABLE ENERGY?"

A. As previously indicated, the Company's fuel costs are a function of (a) fuel prices and (b) the efficiency of the Company's operation and performance of its generating units. The ECAC's fixed efficiency factors are effectively an incentive in place for HECO's generating unit operations and performance. *This highlights the need to carefully consider and establish a reasonable fixed* heat rate in the ECAC such that the appropriate incentive is communicated to the Company regarding the dispatch and operation of its various supply-side sources, as well as its demand-side resources to some degree. Fuel cost changes due to changes in fuel prices are passed through the ECAC to ratepayers. As previously indicated, fuel prices are not within the Company's control and therefore are not manageable by the Company.

With regard to renewables, the ECAC provides HECO with the opportunity to recover or pass through to ratepayers the Company's purchased energy costs for generation provided by independent producers of renewable energy. As explained in the Exhibit D to the Joint Final Statement of Position filed May 11, 2009 and Revised Exhibit C filed June 25, 2009 in the Decoupling Docket (Docket No. 2008-0274), the fixed efficiency factors may incent the utilities to take less renewable energy under certain circumstances.

Analysis has shown that the system heat rate worsens because utility generators must often be taken off of economic dispatch to accommodate increased levels of renewable energy. In the Revised Exhibit C filed in the Decoupling Docket, a process was provided under which the re-determination of the fixed efficiency factors would be undertaken, including:

1. triggers for re-determination of target heat rates;
2. timing for seeking changes in the heat rate target;
3. process for the utility to seek a change to the heat rate target outside of rate cases;
4. justification to change heat rate target; and
5. effective date of change in target heat rate.

Revised Exhibit C also proposed the use of a dead band under sales decoupling for the impact of changes in sales between rate cases, and includes a description of the application of dead bands and the changes to the dead band levels. These matters are addressed in detail in the Revised Exhibit C filed in the Decoupling Docket and in the interest of brevity are incorporated here by reference. The point is that the ECAC with a fixed efficiency factor, modified as circumstances change and the situation dictates (e.g., sales decoupling, addition of large renewable resources, etc.), can provide HECO with incentives to reasonably mange or lower its fuel costs while accommodating greater use of renewable resources.

The Integrated Resources Planning ("IRP") or the Clean Energy Scenario Planning[2] ("CESP") process is the venue where decisions should be made regarding the appropriate balance of reliable resource diversity, compliance with state energy policy and compliance with renewable resource portfolio standards rather than using the ECAC to achieve these objectives. The ECAC essentially should be the risk sharing pass through mechanism for the Company's fuel costs and purchased energy costs (including energy provided by renewable resources) resulting from the implementation of the Company's IRP plan. It is not clear that the elimination of the ECAC would create a significant incentive for a utility company to adopt the greater use of renewables. Further, it is not clear to me how the ECAC can be used to encourage greater use of renewables without either imposing penalties on HECO or increasing costs to ratepayers. An evaluation or a determination must be made as to: (1) whether such punitive measures to the Company and/or ratepayers could reasonably be expected to have the desired effect (i.e., encourage greater use of renewable resources), and (2) that it would be worth the punitive effect borne by HECO and/or ratepayers. Such an evaluation or determination of whether the Company is reasonably considering renewable resource options to meet the customer's energy needs, and

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[2] The IRP process, whose framework was established in Docket No. 6617, was effectively terminated by the Commission's Order Closing Docket filed on November 26, 2008, Docket No. 2007-0084, which terminated the IRP process for the Company. In its place, HECO is working to develop a proposed CESP framework for Commission approval.

whether penalties should be assessed for non-performance should be done in the context of the IRP or CESP process. The Commission had established the IRP Framework and the Companies submitted their IRPs to the Commission for review and approval. If the Commission determined that the IRP submitted did not pursue an appropriate amount of renewable resources, the Commission had the authority to modify the IRP. I assume that the CESP framework and process will allow, at a minimum, the same opportunities for the Commission to set the appropriate levels of renewable resources as targets in the approved clean energy scenario resulting from CESP.

Q. DOES THE COMPANY'S ECAC "ALLOW THE PUBLIC UTILITY TO MITIGATE THE RISK OF SUDDEN OR FREQUENT FUEL COST CHANGES THAT CANNOT OTHERWISE BE REASONABLY MITIGATED THROUGH OTHER COMMERCIALLY AVAILABLE MEANS, SUCH AS THROUGH FUEL HEDGING CONTRACTS?"

A. HECO includes as exhibit HECO-1040 to direct testimony HECO T-10 a copy of a report by NERA on power cost adjustments and hedging fuel sales that was filed in HECO's 2007 Test Year Rate Case (Docket No. 2006-0386). The NERA report points out that hedging, either by physical means or financial instructions, provides a means for locking in a known price at an added cost and that such costs should be passed on to ratepayers (see HECO-1040, pages 16 - 25). The NERA report proposes budget billing and fixed rate billing *as alternatives for smoothing the impact of fuel cost changes on the electric* rates charged ratepayers (see HECO-1040, pages 26 - 34). If the Company cannot achieve non-volatile fuel prices through its fuel purchasing plan, it would seem reasonable that customers who desire less month-to-month fluctuation in their electric charges would have the option of levelizing their payments through budget billing that would not charge the customer more than it otherwise would pay over a period of one year.

Q. WITH RESPECT TO THE FOURTH ITEM "PRESERVE, TO THE EXTENT REASONABLY POSSIBLE, THE PUBLIC UTILITY'S FINANCIAL INTEGRITY" AND THE FIFTH ITEM "MINIMIZE, TO THE EXTENT REASONABLY POSSIBLE, THE PUBLIC UTILITY'S NEED TO APPLY FOR FREQUENT APPLICATIONS FOR GENERAL RATE INCREASES TO ACCOUNT FOR THE CHANGES TO ITS FUEL COSTS," IS THE COMPANY'S ECAC APPROPRIATE FOR CONSIDERATION OF THESE MATTERS?

A. I do not believe there is any question that an ECAC is needed to preserve the Company's financial integrity given the fact that fuel and purchase power expense represents approximately 80 percent of the Company's total operating expenses. HECO should be provided a reasonable opportunity to recover the fuel cost and purchased energy expenses incurred with providing electric service to ratepayers without the need to process back-to-back rate applications. HECO's ECAC provides a means for the Company to timely pass through to ratepayers the changes in fuel and purchased energy costs, as such changes occur, between rate case filings. Absent such an ECAC, the Company would need to have more frequent rate case filings during periods of rising fuel prices to recover the increased cost of fuel and purchased energy and maintain the financial integrity of the Company. Even so, the time that it takes to prepare, fully consider and prosecute a rate case filing would put some additional financial risk exposure on the Company. On the flip side, during periods of falling fuel prices the Company would experience a windfall, absent an Order to Show Cause why the rates should not be reduced to recognize the lower fuel costs and the Commission and the Consumer Advocate would be hard pressed to monitor the Company's financial situation and find a method to provide timely rate relief for ratepayers. In either situation, the administrative burdens on the Company, the Commission and the Consumer Advocate are mitigated with the Company's ECAC.

Q. WHAT CONCLUSIONS SHOULD BE REACHED WITH RESPECT TO THE ACT 162 CONSIDERATIONS OF THE COMPANY'S ECAC?

A. The Company's ECAC provides a fair sharing of the risks of fuel costs changes between the Company and its ratepayers in a manner that preserves the financial integrity of the Company without the need for frequent rate filings.

III. REASONABLENESS OF HECO'S PROPOSED PURCHASED POWER ADJUSTMENT CLAUSE.

Q. DESCRIBE HECO'S PROPOSED PURCHASED POWER ADJUSTMENT CLAUSE.

A. Under HECO's proposed Purchased Power Adjustment Clause, capacity, O&M and other non-energy purchased power payments approved by the Commission will be recovered through a purchased power adjustment clause surcharge that will be adjusted monthly and reconciled quarterly. Fuel related expenses and purchased energy expenses will continue to be recovered through base rates and through the ECAC.

As stated in my direct testimony (see CA-T-2, pp. 54-56), and noted in the Commission's Interim Decision and Order (see page 14), the proposed Purchased Power Adjustment Clause is to address Section 30 of the Energy Agreement among the State of Hawaii, Division of Consumer Advocacy of the Department of Commerce and Consumer Affairs, and the Hawaiian Electric Companies, executed on October 20, 2008 that resulted from the U.S. Department of Energy Clean Energy Initiative ("Energy Agreement"). Since the Consumer Advocate was a party to the Energy Agreement providing for the proposed Purchased Power Adjustment Clause, I primarily looked to issues of implementation and quantification in assessing the reasonableness of this surcharge.

Q. HOW DID YOU ASSESS THE REASONABLENESS OF HECO'S PROPOSED PURCHASED POWER ADJUSTMENT CLAUSE?

A. The State of Hawaii's energy policy includes the acquisition and increased role of renewable energy through purchased power arrangements. In connection with implementing that policy, it is reasonable to have mechanisms in place that provide the utility the opportunity to recover the purchased power cost incurred from third-party resources under arrangements approved by the Commission.

The Commission and the Consumer Advocate will continue to have the opportunity to review, and the Commission will continue to approve, purchased power resources that HECO would procure that would be includable in the amounts to be passed through the purchased power adjustment clause. After the purchased power resource is procured, the Consumer Advocate and the Commission will have the opportunity to review the costs from the purchased power resource that are includable in the purchased power adjustment clause.

Finally, HECO indicates the risks and imputed debt associated with purchased power obligations, as viewed by the financial community rating agencies, differs depending on whether purchased power costs are recovered in base rates or through a power cost adjustment surcharge mechanism (see HECO's Rate Case Update T-20, pages 1 – 6).

Q. DO YOU HAVE ANY OTHER CONCERNS ABOUT THE REASONABLENESS OF THIS CLAUSE?

A. As stated in my direct testimony, I am generally satisfied with the purpose of the clause and the manner that the clause will assess and pass through costs to customers. Since HECO indicated that the purchased power adjustment clause will be adjusted monthly and reconciled quarterly, I recommended in my direct testimony that HECO be required to file its calculations with the Consumer Advocate and the Commission, at least quarterly and that such calculations can be reviewed by the Consumer Advocate and the Commission, to ensure that customers are appropriately charged for purchased power costs. Furthermore, the Commission should require HECO's filing to include all necessary workpapers and supporting documentation that would allow the Consumer Advocate, the Commission and other parties to validate that HECO is not recovering costs more than once through the different cost recovery mechanisms beyond base rates that will be available to HECO.

IV. CONCLUSION.

Q. DOES THIS CONCLUDE YOUR SUPPLEMENTAL TESTIMONY?

A. Yes, it does.

ST-3

S. CARVER

CA-ST-3
DOCKET NO. 2008-0083

SUPPLEMENTAL TESTIMONY AND EXHIBITS

OF

STEVEN C. CARVER

ON BEHALF OF
THE DIVISION OF CONSUMER ADVOCACY

SUBJECT: HECO Interim D&O Changes, HCEI-related Costs, General Expense Increases, A&G Maintenance, Book Depreciation/ADIT, Test Year & 13-Month Average Rate Base, Pension and OPEB Expense

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Description of Exhibits

CA-S300	HCEI-Related Costs Per Settlement Agreement
CA-S301	Revised CA Schedule C-22, Depreciation and Amortization
CA-S302	Revised CA Schedule C-14, Pension & OPEB Cost Adjustment
CA-S303	CA Pension Tracker Illustrations

SUPPLEMENTAL TESTIMONY OF STEVEN C. CARVER

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Steven C. Carver. My business address is P.O. Box 481934, Kansas City, Missouri 64148.

Q. ARE YOU THE SAME STEVEN C. CARVER THAT PREVIOUSLY SPONSORED DIRECT TESTIMONY IN THIS PROCEEDING ON BEHALF OF THE CONSUMER ADVOCATE?

A. Yes. As described in my direct testimony, Utilitech, Inc. was retained by the Department of Commerce and Consumer Affairs, Division of Consumer Advocacy (hereinafter "Consumer Advocate" or "CA") to review and respond to that rate application filed by Hawaiian Electric Company, Inc. (hereinafter "HECO" or "Company") (hereinafter the Consumer Advocate, HECO and the Department of Defense ("DOD") may be specifically and collectively referred to as "Parties") and to prepare direct testimony for filing with this Commission regarding the issues identified during the course of our review.

Q. ARE YOU STILL APPEARING ON BEHALF OF THE CONSUMER ADVOCATE?

A. Yes.

Q. PLEASE SUMMARIZE THE PURPOSE OF YOUR TESTIMONY.

A. On July 2, 2009, the Commission issued an Interim Decision and Order ("Interim D&O") in this proceeding. In addition to the two issues that were not resolved by the Parties through settlement discussions and were scheduled for hearing,[1] the Interim D&O identified other areas of interest to the Commission on which the Parties may file additional testimony. Generally, my supplemental testimony will address certain of those additional areas identified by the Commission, including:

- HECO's proposed changes to comply with the Interim D&O;
- the identification of certain HCEI-related implementation or research and development costs addressed in the Settlement Agreement;
- general expense increases;
- A&G maintenance normalization;
- book depreciation and related ADIT reserve effects;
- thirteen-month average rate base;
- and pension and OPEB expenses.

Mr. Michael Brosch (CA-ST-1 and CA-ST-5), Mr. Joseph Herz (CA-ST-2) are also sponsoring supplement testimony on behalf of the Consumer Advocate to address certain additional areas identified in the Interim D&O.

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[1] Return on common equity and informational advertising.

I. **HECO'S INTERIM D&O CHANGES.**

Q. IN ORDERING PARAGRAPH 2 OF THE INTERIM D&O, THE COMMISSION DIRECTED HECO TO FILE REVISED SCHEDULES TO REMOVE CERTAIN COSTS, INCLUDING A REFERENCE TO SECTION II.1, FROM THE AMOUNT OF INTERIM RATE RELIEF. ARE YOU FAMILIAR WITH THE INTERIM D&O?

A. Yes.

Q. HAVE YOU REVIEWED HECO'S REVISIONS TO THE AMOUNT OF INTERIM RELIEF THAT WAS FILED WITH THE COMMISSION ON JULY 8, 2009, IN RESPONSE TO THE INTERIM D&O?

A. Yes. Exhibit 3 of HECO's July 8, 2009 filing[2] (hereinafter the "July 8th Filing") described the various adjustments proposed by the Company to bring the amount of interim relief into compliance with the Interim D&O. These adjustments are numerically summarized on HECO Attachment A. Mr. Brosch (CA-ST-1) and I have reviewed the Company filing and supporting documentation. I have also participated in a conference call with HECO personnel to discuss the Company workpapers supporting the wage-related adjustments.

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[2] The July 8, 2009, filing by HECO was captioned: Docket No. 2008-0083 - Hawaiian Electric 2009 Test Year Rate Case, REVISED Schedules Resulting from Interim Decision and Order.

Q. ON JULY 15, 2009, THE CONSUMER ADVOCATE FILED COMMENTS ON HECO'S JULY 8TH FILING RESPONDING TO THE INTERIM D&O. ARE YOU FAMILIAR WITH THE COMMENTS OF THE CONSUMER ADVOCATE?

A. Yes. The Consumer Advocate's comments expressed the belief that HECO'S July 8th Filing was conservatively prepared and in compliance with the Interim D&O.

Q. PLEASE IDENTIFY THE PORTIONS OF HECO'S JULY 8TH FILING THAT YOU REVIEWED.

A. In order to expedite review by the Consumer Advocate, HECO's compliance filing adjustments were apportioned between Mr. Brosch and I based on the general division of responsibilities from the start of this engagement. Consequently, I reviewed the HECO response in the areas of HCEI employee positions, merit wage rates, CT-1 elimination and the effect of commodity prices on T&D materials and supplies.

Q. IN THESE AREAS, PLEASE EXPLAIN WHY YOU BELIEVE HECO'S ADJUSTMENTS WERE CONSERVATIVELY PREPARED.

A. The two labor related adjustments were prepared using what I believe are conservative assumptions. Regarding the adjustment for HCEI employee positions (Interim D&O Section II.1(b) and HECO Exhibit 3, pages 3 through 5), the Company removed 100% of the applicable labor costs and related employee benefits and payroll taxes previously included in the 2009 test year expense forecast as part of HECO's December Rate Case Update. The Company has indicated that the employee positions, identified as being related to HCEI programs, have other work activities and responsibilities outside of HCEI programs. In order to comply with its interpretation of the Interim D&O, however, the Company removed 100% of the labor and benefits costs included in expense for these positions, rather than limit the removal to a partial allocation of such costs between HCEI and non-HCEI activities.

The Interim D&O also restricted merit employee wage levels "to 2007 or *the most recent actual labor costs filed with the commission*, taking into account the vacancy rate agreed upon by the Parties on pages 22 and 23 of the Settlement Agreement." See Interim D&O Section II.2(c). In response, HECO (Exhibit 3, pages 11 through 13) quantified an adjustment to merit labor expense employing standard labor rates at year-end 2007 and merit labor hours from its direct filing, without any offset for the agreed to vacancy rate effects. In other words, the merit pay adjustment presented by HECO in the July 8th Filing appears to produce a larger reduction to O&M expense than would have been quantified if the vacancy rate had been considered in calculating the adjustment. Based on this understanding, the merit adjustment appears to be conservative.

II. HCEI-RELATED COSTS.

Q. ORDERING PARAGRAPH 2 OF THE INTERIM D&O, DIRECTING HECO TO REMOVE CERTAIN COSTS FROM THE AMOUNT OF INTERIM RATE RELIEF, ALSO REFERS TO SECTION II.1. WHAT IS THE SUBJECT OF SECTION II.1?

A. Section II.1 of the Interim D&O concerns the Commission's discussion and direction that certain HCEI-related items should be removed from the amount of interim relief as not passing the "probable entitlement" test because those HCEI-related items have not yet been approved by the Commission. As part of HECO's July 8th Filing, at page 6 of HECO Exhibit 3, the Company discusses HCEI-Related Outside Services and concludes that no further adjustment was necessary.[3]

On July 15, 2009, the Consumer Advocate submitted its response to HECO's July 8th Filing, generally stating that the Company's revisions to the quantification of interim relief are in compliance with the Interim D&O. However, the Consumer Advocate also advised the Commission that the July 8th Filing did not address or propose adjustments for certain non-labor costs that are identified as HCEI-related implementation costs or research and development ("R&D") study costs in the joint Stipulated Settlement Letter filed with the Commission on July 15, 2009.[4] The Consumer Advocate expressed its uncertainty whether the

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3 Also, see Column D of Attachment A (pages 1 and 2) showing no adjustment proposed by HECO associated with HCEI-Related Outside Services.

4 See the Stipulated Settlement Letter, Exhibit 1, pages 18-22, and pages 5-6 of HECO's Statement of Probable Entitlement, filed on May 18, 2009.

Commission meant to exclude only incremental HCEI costs identified in the Interim D&O from the amount of interim relief or also intended the exclusion of all costs related to programs or initiatives associated with the HCEI Agreement.

Q. WHY ARE YOU DISCUSSING HCEI-RELATED COSTS IN THIS SUPPLEMENTAL TESTIMONY?

A. Attachment 1 to the Consumer Advocate's reply filed on July 15, 2009, represents a table showing the amount of HCEI-related implementation costs and R&D study costs that still remain within the amount of HECO's revised calculation of interim relief of $61,098,000. Because of the Consumer Advocate's uncertainty as to the intent of the Interim D&O to include or exclude these costs from the amount of interim relief, the Consumer Advocate determined that it was appropriate to so communicate the amount of such cost to the Commission. I prepared that Attachment 1 for the Consumer Advocate and have appended a copy to this supplemental testimony as Exhibit CA-S300.

Q. IS THE CONSUMER ADVOCATE RECOMMENDING THE INCLUSION OR EXCLUSION OF THESE HCEI-RELATED COSTS FROM THE AMOUNT OF INTERIM RELIEF THE COMMISSION SHOULD AUTHORIZE FOR HECO?

A. The Consumer Advocate is not recommending the inclusion or exclusion of these costs at this time. Rather, the Consumer Advocate is simply advising the Commission that the Settlement Agreement and HECO's revised interim relief request includes $1,491,000 of these HCEI-related costs. Whether it was the intent of the Interim D&O to include or exclude these costs from the amount of interim relief to be granted HECO is for the Commission to determine.

III. GENERAL EXPENSE INCREASES.

Q. AT PAGE 16, SECTION III.(J) OF THE INTERIM D&O, THE COMMISSION NOTED THAT THERE APPEARS TO BE SIGNIFICANT INCREASES IN CERTAIN EXPENSES BETWEEN THE 2007 TEST YEAR INTERIM AWARD AND THE 2009 TEST YEAR. COULD YOU EXPLAIN THE CONSUMER ADVOCATE'S APPROACH TO REVIEWING HECO'S FORECAST OF OPERATING AND MAINTENANCE EXPENSE IN THE CONTEXT OF A GENERAL RATE CASE?

A. Yes. With the exception of the State of California, Hawaii's regulatory requirement to employ a forecast test year is rather unique in my regulatory experience, as most State regulatory jurisdictions use a historic test year with consideration of certain known and measurable changes occurring subsequent to the historic test year. Since Hawaii's utility rate filings rely on a forecast test year, Utilitech has worked with the Consumer Advocate over the years to develop a forecast review and evaluation approach unique to Hawaii's test year requirements.

Rather than simply rely on recent trends in historic operations and maintenance ("O&M") expenses to assess utility test year expense forecasts, several analytical techniques are employed to drill down into the detailed forecast documentation compiled by the utility to support its rate filing. The following outline generally summarizes those techniques:

- Obtain and review the detailed exhibits and supporting workpapers prepared and relied upon by each utility witness, including hardcopy documents and underlying magnetic files and utility variance analyses.
- Submit standardized information requests applicable to each subject matter expert for additional labor (CA-IR-1), non-labor (CA-IR-2) and other forecast workpapers or documents (CA-IR-3) developed in preparation of the rate case forecast but not prefiled with direct testimony. This information is obtained in both hardcopy and magnetic file formats.
- Schedule informal interviews with key utility subject matter witnesses (e.g., production; transmission and distribution; customer service; customer accounts; administrative and general; operating and miscellaneous revenue; plant and reserve; income tax expense and ADIT reserve; taxes other than income taxes; cash working capital; wage, salary and employee counts; employee benefits; etc.) for the purpose of walking through the detailed workpapers to identify key changes and cost drivers for subsequent follow-up.

- Submit information requests across multiple sets to follow-up on information communicated during the informal interview process and to obtain data confirmation, additional documentation and rationale for assumptions or other factors underlying the test year forecast.

By definition, the Hawaii forecast test year is based on estimates of future costs rather than historic, actual costs. As a result, the above technique is somewhat similar to what is employed in a historic test year environment but is decidedly focused on detailed data underlying utility forecasts and estimates. There may be times, depending on the circumstances, that historical averaging may be relied upon (e.g., expense normalization, uncollectible factors, etc.). But because Hawaii statutes require the use of a forecast test year, historical data may not be reliable for test year purposes due to expected future changes that need to be considered (e.g., wage/salary increases, actuarial study revisions, new plant addition, etc.).

Q. HAS HECO'S FORECAST OF 2009 TEST YEAR O&M EXPENSES INCREASED SINCE THE 2007 RATE CASE TEST YEAR, DOCKET NO. 2006-0386?

A. Yes. O&M expenses have generally increased over time. While I have not prepared a specific comparative analysis of labor and non-labor cost trends for purposes of this supplemental testimony, the direct testimony of each HECO witness with primary responsibility for major categories of expense have prefiled comparative exhibits and variance analyses that are reviewed by and often serve as the basis for information requests submitted by the Consumer Advocate.

Q. DOES THIS TECHNIQUE YOU DESCRIBE RESULT IN THE REVIEW OF EVERY DOLLAR OF FORECAST EXPENSE BY THE CONSUMER ADVOCATE?

A. No. The utility's preparation of the base test year forecast spans many months and involves many more utility employees than those that file direct testimony.[5] The detailed, bottom-up forecast process employed by HECO can be reviewed, evaluated and adjusted by the Consumer Advocate, but not replicated within the time and resource constraints of a typical rate case proceeding.

Q. ARE THE INDIVIDUAL ADJUSTMENT SCHEDULES SET FORTH IN EXHIBIT CA-101 THE RESULT OF THESE CONSUMER ADVOCATE REVIEW TECHNIQUES?

A. Yes.

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5 See, for example, HECO's responses to CA-IR-1, CA-IR-2 and CA-IR-3. A standard element of each of these information requests is for a listing of the Company employees involved in the preparation of budgeted staffing, labor hour, labor costs, and non-labor costs.

Q. DO YOU HAVE ANY FINAL COMMENTS ON THIS PORTION OF THE INTERIM D&O?

A. A regulated utility has the burden of supporting the reasonableness of any requested change in its rates and tariffs. I would expect that HECO will provide a much more detailed response to the Commission's Interim D&O than has been addressed herein. Nevertheless, the Consumer Advocate's direct testimonies and exhibits represent the result of months of effort and detailed review of voluminous data accompanying a utility filing and documents supplied in response to formal discovery.

IV. A&G MAINTENANCE.

Q. IN SECTION IV OF THE INTERIM D&O, THE COMMISSION DIRECTED THE PARTIES TO PROVIDE WITNESSES AT THE EVIDENTIARY HEARING CAPABLE OF ANSWERING QUESTIONS AS TO THE REASONABLENESS OF THE SETTLEMENT AGREEMENT IN FIVE IDENTIFIED AREAS. AT PAGE 17, SECTION IV.(B) THE COMMISSION IDENTIFIES A&G MAINTENANCE NORMALIZATION AS ONE OF THE AREAS OF INTEREST. ARE YOU FAMILIAR WITH THIS PORTION OF THE TESTIMONY AND SETTLEMENT AGREEMENT?

A. Yes. My direct testimony presented the Consumer Advocate's position on this issue.[6]

Q. ONE OF THE POINTS RAISED IN SECTION IV.(B) OF THE INTERIM D&O IS THAT THE COMMISSION AGREES WITH THE INITIAL AVERAGING POSITION OF THE CONSUMER ADVOCATE FOR NORMALIZATION PURPOSES, BUT INDICATES THAT THE AVERAGE SHOULD BE BASED ON 2006-2008 ACTUALS AND EXCLUDE THE 2009 FORECAST. DO YOU HAVE ANY COMMENT?

A. Yes. While formulating the normalization methodology presented in the Consumer Advocate's direct filing, consideration was given to using an average

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[6] Carver direct testimony (CA-T-3), pp. 60-63.

of the 2006-2008 actual nonrecurring A&G maintenance expense. However, this normalization approach was not proposed due to the recent observed increases in actual nonrecurring A&G maintenance costs coupled with HECO's forecasts for 2009 and 2010, all heavily influenced by the Ward parking structure and Ward baseyard maintenance projects. For ease of reference, the following table summarizes this information:

(000's)	Actual Average	CA Proposed	HECO Update	Settlement
2006 Actual	$ 93	$ 93		
2007 Actual	363	363		
2008 Actual	1,330	1,330	$ 880	
2009 FCST		1,012	1,072	
2010 FCST			700	
Average	$ 595	$ 700	$ 884	
Proposed		$ 700	$ 969	$ 824

Sources: Exhibit CA-101, Schedule C-18; HECO T-14 Update, p. 19; Settlement Agreement, p. 55.

While the Consumer Advocate does not necessarily disagree with the Commission's stated preference for an average of historical data for normalization purposes, the increasing cost trend pointed in another direction for purposes of this case. Hopefully, the extensive nonrecurring maintenance projects that have been occurring at the Ward facility will reach conclusion by the Company's next rate case. In the meantime, the Consumer Advocate's initial averaging approach balanced the early years of relatively limited nonrecurring maintenance and the more extensive maintenance in 2008 and planned for 2009. In that next HECO rate case, the facts and circumstances could lead the

Consumer Advocate to recommend a normalization methodology that may or may not be a historical averaging approach,

As stated at page 55 of the Settlement Agreement, the Consumer Advocate did not agree with the methodology employed by HECO nor accept the DOD's proposed methodology, although the $824,000 amount was agreed as acceptable solely for settlement purposes and only for this rate case. The acceptability of the $824,000 for settlement purposes was due to the fact that the positions of the parties were fairly narrowly bounded between $700,000 and $969,000, with the settlement value falling mid-range.

Q. SECTION IV.(B) OF THE INTERIM D&O ALSO REFERRED TO $145,000 OF PARKING STRUCTURE COSTS THAT THE PARTIES AGREED SHOULD BE CAPITALIZED, INDICATING THAT THOSE COSTS SHOULD BE REMOVED PRIOR TO ANY AVERAGING CALCULATIONS. DO YOU HAVE ANY INFORMATION REGARDING THE $145,000?

A. Yes. The $145,000 that is capital-related is discussed in HECO's response to CA-IR-348. This amount was included in the $525,000 2009 Ward Baseyard Project set forth in the HECO T-14 Update, page 19. Referring to Exhibit CA-101, Schedule C-18, footnote (b), this $145,000 amount was removed from HECO's 2009 forecast amount in quantifying the Consumer Advocate's original normalization adjustment.

V. BOOK DEPRECIATION & ADIT.

Q. SECTION IV.(C)2 OF THE INTERIM D&O OBSERVES THAT THE $1,098,000 OF BOOK DEPRECIATION EXPENSE AND $417,000 OF ADIT APPEARING ON PAGE 75 OF EXHIBIT 1 OF THE SETTLEMENT AGREEMENT ARE NOT SUPPORTED BY THE REFERENCED "CA-101, SCHEDULE C-22." THE INTERIM D&O THEN STATES THAT THE PARTIES MAY PROVIDE WORKPAPERS SHOWING THE CALCULATIONS UNDERLYING THE BOOK DEPRECIATION ADJUSTMENT. ARE YOU FAMILIAR WITH EXHIBIT CA-101, SCHEDULE C-22?

A. Yes. I prepared and sponsored CA Schedule C-22 in direct testimony.[7]

Q. EXHIBIT CA-101, SCHEDULE C-22 SHOWS AN ADJUSTMENT TO BOOK DEPRECIATION AND AMORTIZATION EXPENSE OF $(2,197,000). WHY DOES PAGE 75 OF EXHIBIT 1 OF THE SETTLEMENT AGREEMENT REFER TO A NET REDUCTION TO BOOK DEPRECIATION EXPENSE OF $1,098,000?

A. Subsequent to the filing of the Consumer Advocate's direct testimony and exhibits, the Consumer Advocate was informed that HECO had inaccurately forecast the amount of net unrecovered amortization appearing on line 3 of CA Schedule C-22. Instead of $1,924,000, the amount of remaining amortization should have been $2,198,000.

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7 See CA-T-3, pp.86-89.

Pursuant to further settlement discussions between the parties, the Consumer Advocate agreed to a two-year prospective amortization of the corrected amount of $2,198,000. See pages 60 and 61 of Exhibit 1 of the Settlement Agreement.

When the various exhibits and attachments to the Settlement Agreement were compiled, the revision to CA Schedule C-22, supporting the $1,098,000 referenced in the Interim D&O, was not among the documents accompanying the Settlement Letter.

Q. WAS A REVISED CA SCHEDULE C-22 PREPARED DURING THE SETTLEMENT DISCUSSIONS THAT SUPPORTS THE $1,098,000 REDUCTION TO DEPRECIATION EXPENSE?

A. Yes. Exhibit CA-S301 attached hereto represents that revised CA Schedule C-22.

Q. IS THE RELATED $417,000 INCREASE TO THE ADIT RESERVE QUANTIFIED ON EXHIBIT CA- S301?

A. No. As explained at page 75 of Exhibit 1 to the Settlement Agreement, the reduction in book depreciation and amortization expense of $1,098,000 results in an increase to the 2009 year-end ADIT reserve of $427,000 (i.e., $1,098,000 x 38.91%), which has a corresponding reduction to average rate base by one-half of this change or $214,000 (i.e., 50% x $427,000 = $213,500, or rounded to $214,000).

VI. TEST YEAR & 13-MONTH AVERAGE RATE BASE.

Q. SECTION IV.(D) OF THE INTERIM D&O REFERS TO THE TWO POINT AVERAGING TECHNIQUE USED FOR RATE BASE, AS DISCUSSED AT PAGE 64 OF EXHIBIT 1 OF THE SETTLEMENT AGREEMENT. THE COMMISSION THEN REQUESTED THE PARTIES TO FILE TESTIMONY DISCUSSING WHETHER THIS METHOD OR AN ALTERNATIVE THIRTEEN-MONTH AVERAGE WOULD BE MORE APPROPRIATE, GIVING LESS WEIGHT TO LARGE LATE-YEAR CAPITAL ADDITIONS LIKE CT-1. ARE YOU FAMILIAR WITH RATE BASE VALUATION APPROACHES?

A. Yes. My direct testimony (CA-T-3, pages 12 through 17) generally discusses the ratemaking equation and various approaches to test year selection (i.e., historic vs. forecast) and application (i.e., average vs. year-end). One of the key elements for the ratemaking equation to function properly is that the components comprising the equation (i.e., rate base, revenues, expenses and rate of return) must be reasonably representative of ongoing levels, internally consistent and comparable.

In my experience in Hawaii dating back to the early 1990's, this Commission has used a forecast test year and employed an average approach. For rate base, the average is a two-point average of beginning and ending test year balances, sometimes referred to as the "simple average." For revenue and expenses, the average concept does not allow annualization of revenues or expenses (e.g., volumes or prices) to year-end levels.

Q. HAVE YOU SEEN REGULATORY COMMISSIONS APPLY A THIRTEEN-MONTH AVERAGE APPROACH FOR RATE BASE VALUATION PURPOSES?

A. Yes. However, the use of a thirteen-month average is typically limited to a historic test year and to rate base components that tend to fluctuate from month to month with no discernable trend – such as, materials and supplies, prepayments, customer deposits, customer advances, etc. While there are certainly exceptions, historic test years normally employ year-end balances for the other rate base components that do show an upward or downward trend, like plant in service, accumulated depreciation reserve, accumulated deferred income tax reserve, etc.

Q. WHY DID THE CONSUMER ADVOCATE RELY ON THE TWO-POINT AVERAGE APPROACH TO VALUE RATE BASE FOR PURPOSES OF HECO'S 2009 FORECAST TEST YEAR?

A. The Consumer Advocate applied the two-point average approach to rate base for several reasons.

- This approach is consistent with long standing Commission practice.

- If the valuation technique or method were to be altered, it would be important to identify which items should be modified and assess whether there are other forecast components that also merit revision.
- Campbell Industrial Park ("CIP") CT-1 was expected to be completed and placed in service during the month of July 2009, approximating the mid-year convention presumed by a two-point average.
- Capital projects may be completed and placed in service throughout the year – some early and some late. The two-point average method treats all projects on a consistent basis, regardless of completion.

Q. IN YOUR OPINION, ARE THERE PRACTICAL LIMITATIONS TO THE USE OF A THIRTEEN-MONTH AVERAGE APPROACH TO VALUE RATE BASE IN A FORECAST TEST YEAR ENVIRONMENT?

A. Yes. By its very nature, a forecast test year is built on a multitude of estimates and assumptions. For purposes of forecasting year-end plant in service, the Company must provide its best estimate of when individual construction projects are expected to be completed and placed into utility service. Under a two-point average approach, the critical determination is to get the "year" (e.g., 2008, 2009, 2010, etc.) of project completion and in-service correct.

Under a thirteen-month average approach, the forecasting emphasis must be even more precise to accurately identify the month of the forecast test year that each capital project is most likely to be completed and placed into utility service. In my opinion and experience, adoption of a thirteen-month average approach would imply a much higher degree of precision in the utility rate case forecast process than actually exists.

If, for future rate proceedings, the parties were required to deal with a 13-month average for all rate base estimates, this would most likely lead to a significant increase in the amount of work and issues that might be at dispute. Currently, the Consumer Advocate generally highlights those capital projects projected to be completed near the end of a test period for additional scrutiny regarding the completion date. Using a 13-month average, the Company would have to provide significantly more documentation to support the asserted completion date and the Consumer Advocate would have to conduct additional tests in order to attempt to identify the reasonable completion date narrowed to a single month, rather than a year.

Q. SO, IS IT YOUR OPINION THAT THE COMMISSION HAS NO OPTION BUT TO CONTINUE TO USE THE TWO-POINT AVERAGE APPROACH EVEN IF FACTS AND CIRCUMSTANCES SUGGEST THAT CIP CT-1 WILL NOT BE COMPLETED AND PLACED INTO UTILITY SERVICE UNTIL LATE IN 2009?

A. No. I believe that alternatives could be considered. However, it might not be appropriate to implement those alternatives in the instant proceeding, absent advance notice to the utility. The Commission may wish to explore those alternatives in a separate proceeding or in a work shop or a task force outside of a pending rate application, where the results of that effort could then be adopted on a prospective basis. Implementing an alternative methodology in the instant proceeding, especially for one item, would cause internal inconsistencies in comparison to the methodology used to recognize other rate base items.

While it is my understanding that the Commission has, under the broad authority granted to the Commission, the ability to require something other than the two-point average approach in the instant proceeding, such as a 13-month average, it might be inappropriate to do so at this time. Such a decision could result in unintended consequences.

For instance, the need for and timing of a rate case filing by a regulated utility may be driven, in part, by the planned completion of a major construction project. If the major project were expected to be completed early in the first half of the forecast test year and a 13-month average or some other weighting technique were employed, the determination of the calculated revenue increase would approach a full "annual" effect the closer the completion date is to January 1.

Similarly, the unintended and unplanned slippage of a major project's completion schedule late in the forecast year would result in fractional rate relief the closer the expected completion date is to December 31. Depending on the magnitude of the major project on overall revenue requirement, a fractional rate award could result in the immediate filing of another rate case to implement the balance of the needed rate relief.[8]

With advance notice of such a weighting technique, a utility may elect to alter the timing of <u>when</u> to file a rate case based on whether completion of the major construction project is highly likely to occur early or late in the forecast test year.

VII. PENSION & OPEB EXPENSE – REGULATORY ACCOUNTING.

Q. SECTION IV.(E) OF THE INTERIM D&O REFERS TO THE HIGH AMOUNT OF PENSION AND OPEB COST INCLUDED IN THE SETTLEMENT AGREEMENT (AT PAGES 53 AND 54) AND EXPRESSES COMMISSION CONCERN FOR POTENTIAL OVER-RECOVERY. ARE YOU FAMILIAR WITH THESE MATTERS?

A. Yes. My direct testimony (CA-T-3, pages 21 through 32) discusses several subtopics relevant to this portion of the Interim D&O: (i) the continuation and operation of the pension and OPEB tracking mechanisms implemented in HECO's last rate case (Docket No. 2006-0386) and (ii) the Consumer Advocate adjustments[9] to reflect the 2009 actuarial study results and the rate base

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8 This scenario of unintended consequences presumes that there is no approved decoupling mechanism or related revenue adjustment mechanism in a form substantially similar to those *presented to the Commission in Docket No. 2008-0274.*

9 See Exhibit CA-101, Schedules C-14, B-2 and B-7.

recognition of regulatory asset/liability and ADIT reserve effects resulting from the tracking mechanisms.

Q. PLEASE DISCUSS THE CONCERN ABOUT OVER-RECOVERY.

A. At page 20, the Interim D&O states the concern, as follows:

> On pages 53 and 54 of the Settlement Agreement, the Parties agreed to collect through rates $14,042,000 of pension and other post employment benefit ("OPEB") contributions. This high amount of pension and OPEB contributions is in response to a reduction in the value of plan assets and a decrease in the return of pension assets. If the next rate case's test year is 2011, rates from this proceeding could be in effect for two years. This could facilitate revenue collection in excess of that needed to ensure the solvency of the pension and OPEB funds. The commission is concerned about such over-recovery as well as the potential for actual contributions to fall below the amount recovered through rates if an economic recovery improves asset value and performance. The Parties may provide testimony describing whether the pension and OPEB funds are externally managed "lock box" funds and whether there are any mechanisms to prevent contributions from being used for general utility operations or given to shareholders. The Parties should also describe what mechanisms, if any, ensure that HECO contributes to the pensions and OPEB funds the amount it recovers for these costs through rates.

The Consumer Advocate very much appreciates the Commission's concern that the pension and OPEB costs included in rates are reasonable and that ratepayer interests are protected in light of the "high amount" of such costs included in the Settlement Agreement. Given the complexity of the Commission's inquiries, the remainder of this testimony section will address the following key points:

- What is the amount of pension and OPEB costs that have been included in the Settlement Agreement?

- How does the amount of pension and OPEB costs included in rates relate to the amount of contributions made to external funds?

- Are there mechanisms that have been or should be implemented to protect ratepayer interests and to ensure that the amount of fund contributions are appropriate?

Q. DOES THE $14,042,000 REFERENCED IN THE ABOVE EXCERPT FROM THE INTERIM D&O REPRESENT THE TOTAL AMOUNT OF PENSION AND OPEB COSTS THE SETTLEMENT AGREEMENT PROPOSES TO INCLUDE IN RATES?

A. No. The $14,042,000 amount referenced in the Interim D&O is the net O&M expense adjustment to the amount of pensions and OPEB expense HECO included in its December Rate Case Update. Attached hereto as Exhibit CA-S302 is a revised CA Schedule C-14 showing the calculation of the $14,042,000 employee benefit expense adjustment. The revised 2009 pension and OPEB forecast amounts[10] set forth on Exhibit CA-S302 also tie to HECO T-13, Attachment 2 of the Final Settlement. For reference purposes, the following table recasts the amounts from Exhibit CA-S302 to more clearly show the revised 2009 actuarial forecast of total NPPC and NPBC and how those amounts are allocated to O&M expense:

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10 In response to DOD-IR-101, HECO provided a revised 2009 forecast of net periodic pension costs ("NPPC") prepared by its actuarial consultant that increased NPPC from 14,623,000 to $31,488,000 (before allocation between expense and capital accounts). OPEB costs are also identified as net periodic benefit costs ("NPBC").

(000's)	Pensions (NPPC)	OPEBs (NPBC)	Total
2009 Revised NPPC/NPBC	$ 31,489	$ 6,923	$ 38,412
Reg. Asset/Liab. Amort.	994	107	1,101
Subtotal	32,483	7,030	39,513
Allocation to O&M Exp.	71.41%	71.41%	71.41%
Revised Expense FCST	$ 23,196	$ 5,020	$ 28,216
HECO Update FCST	$ 14,623	$ 5,224	$ 19,847
Allocation to O&M Exp.	71.41%	71.41%	71.41%
HECO Update Expense	$ 10,442	$ 3,730	14,172
Revised FCST Adjustment (a)	$ 12,754	$ 1,290	$ 14,044

Note (a): Difference between $14,042 and $14,044 due to rounding.
Sources: Exhibit CA-S302 & HECO T-13, Attachment 2, Final Settlement.

While the Settlement Agreement accurately identified the $14,042,000 amount as the agreed to pensions and OPEB expense adjustment, the total amount of pensions and OPEB expense included in the 2009 test year forecast is about $28.2 million, as set forth in the above table.

Q. THE EXCERPT FROM THE INTERIM D&O USES THE WORD "CONTRIBUTIONS" IN THE CONTEXT OF THE $14,042,000 ADJUSTMENT AMOUNT. USING PENSIONS AS AN EXAMPLE, PLEASE EXPLAIN THE DIFFERENCE BETWEEN NET PERIODIC PENSION COSTS, PENSION EXPENSE AND PENSION CONTRIBUTIONS.

A. As generally indicated in direct testimony, NPPC are quantified annually by the Company's actuarial consultant for public financial statement disclosure purposes pursuant to FAS87.[11] The $31,489,000 amount on the first line of the above table is the revised 2009 NPPC forecast prepared by the Company's actuarial consultant and supplied in response to DOD-IR-101. The following table from my direct testimony (CA-T-3, page 27) shows the components of NPPC and summarizes the change in the NPPC components between the Company's original and recently revised 2009 forecast amounts:

	2009 Forecast (000's)		
	Original	Revised	Difference
Service Cost	$ 19,631	$ 16,943	$ (2,688)
Interest Cost	40,377	40,486	109
Expected Return	(48,858)	(36,230)	12,628
Amort. Transition Oblig.	0	0	0
Amort. Prior Service Cost	(465)	(465)	0
Amort. (Gain)/Loss	3,938	10,754	6,816
Total NPPC	$ 14,623	$ 31,488	$ 16,865

Source: HECO T-13, p. 11 & DOD-IR-104, Attachment 4A.

Because all eligible HECO employees are covered by the pension retirement plan and a portion of the labor costs of those employees get allocated to capital projects or may be billed to third parties, only a portion of the total pension costs (NPPC) of $31,488,000 will be charged to O&M expense. Using a composite O&M expense allocation factor of 71.41%, about $22,486,000 of the total NPPC of $31,488,000 would be included in expense for accounting and ratemaking purposes.

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11 See CA-T-3, pages 22 through 26. References to NPPC are in the context of Statement of Financial Accounting Standards No. 87 ("FAS87"), as subsequently amended and revised.

The calculation of the amount of required (i.e., minimum) or allowed (i.e., maximum) contributions to the external pension trust fund is separately calculated by the Company's actuarial consultant. Due to increasing national concerns over the past several years whether employers have adequately funded external pension trusts, Congress enacted and the President signed into law first the Pension Protection Act ("PPA") and then the Worker, Retiree, and Employer Recovery Act of 2008 ("WRERA"). While these laws help define the amount of minimum or required pension contributions, there are also contribution limits established in the Internal Revenue Code that essentially cap the amount of annual contributions by prescribing the maximum pension contribution that can be deducted for Federal income tax purposes. In direct testimony, HECO T-11 (page 73) stated that the Company did not make any pension fund contribution in 2007 and did not expect to make any contributions in 2008 or 2009. However, as indicated by the supplemental responses to DOD-IR-101 and DOD-IR-104 (dated March 27, 2009), PPA and WRERA[12] will result in a minimum contribution requirement in 2009 of $8,218,000 and a likely contribution in 2010.[13]

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12 Neither the PPA nor WRERA have any current effect on the calculation of NPPC. However, any additional pension fund minimum contribution requirements would impact future year NPPC calculations due to the incremental effect of higher plan assets.

13 According to the response to DOD-IR-104 (Supplement 3/27/09), WRERA may help lower the final 2009 minimum contribution requirement to be partially contributed in 2009 with the remainder due in 2010. The $8,218,000 contribution in 2009 is not expected to change, but any contribution reduction due to WRERA would be realized in 2010. The response to CA-IR-243 (Supplement 3/30/09) states that additional pension funding relief was sought in March 2009, with additional guidance from the Treasury Department expected as early as May 2009.

Q. BASED ON THIS SUPPLEMENTAL TESTIMONY, THERE DOES APPEAR TO BE A DISCONNECT BETWEEN THE AMOUNT OF PENSION COSTS INCLUDED IN RATES AND PENSION CONTRIBUTIONS. IS THERE ANY MECHANISM TO RECONCILE THIS DIFFERENCE AND PROTECT RATEPAYERS FROM POSSIBLE OVER-RECOVERY OF NPPC SHOULD THE RATES RESULTING FROM THIS RATE CASE REMAIN IN EFFECT FOR TWO YEARS?

A. Yes. In direct testimony, Company witness Patsy Nanbu discusses HECO's accounting for both pension and post retirement benefits other than pension ("OPEB") costs[14] and the pension and OPEB tracking mechanisms that were implemented in the Company's last rate case, Docket No. 2006-0386,[15] which HECO proposes to continue in the current proceeding.

The Consumer Advocate also filed direct testimony in this proceeding that explained and supported the continuation of the pension and OPEB tracking mechanisms.[16]

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14 HECO T-11, pages 66-78.

15 In Decision and Order No. 23749, issued October 22, 2007, the Commission approved the pension and OPEB tracking mechanisms on an interim basis.

16 CA-T-3, pages 22-23 and 28-31.

Q. HOW DOES THE PENSION TRACKING MECHANISM RECONCILE PENSION COSTS AND PENSION CONTRIBUTIONS AND PROTECT RATEPAYERS FROM OVER-RECOVERY?

A. As the Commission will recall, concepts and issues surrounding this "disconnect" were presented in HECO's 2005 rate case test year (Docket No. 04-0113). In that case, the issue focused on whether a prepaid pension asset should be included in rate base – HECO said "yes" and the Consumer Advocate said "no." The interim decision in HECO's 2005 rate case initially found that HECO was probably entitled to include the prepaid pension asset in rate base, net of the related ADIT reserve.[17] Subsequent to the settlement agreement between HECO, the Consumer Advocate and the Department of Defense in the following 2007 rate case test year (Docket No. 2006-0386) implementing the pension tracking mechanism, the Commission issued a subsequent decision in HECO's 2005 rate case finding that "the prepaid pension asset should be excluded from rate base."[18]

However, the Consumer Advocate first proposed a pension tracking mechanism in the 2006 rate case test year of Hawaii Electric Light Company

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[17] Interim Decision & Order No. 22050, Docket No. 04-0113, p. 9, dated September 27, 2005.

[18] Decision & Order No. 24171, Docket No. 04-0113, p. 9, dated May 1, 2008.

(i.e., Docket No. 05-0315).[19] The intent was to create a mechanism that allowed the utility over time to recover through rates actual NPPC, but also protected ratepayers from having rates set on a level of NPPC that was materially higher or lower than actual NPPC. The intent and operation of the tracking mechanism has not changed.

Stated another way, the tracking mechanism was designed to avoid the very situation about which the Interim D&O is concerned – setting rates on a high (or low) level of pension costs and the potential for over-recovery (or under-recovery) during the period those rates remain in effect. Based on my review of HECO's actual experience under the pension tracking mechanism since its implementation in the 2007 rate case, it appears to be working as designed.

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19 The Consumer Advocate and HELCO entered into a stipulation and agreement that, among other provisions, reflected the parties' concurrence in a pension tracking mechanism substantially similar to the mechanism agreed to by the Consumer Advocate and HECO (Docket No. 2006-0386) and again proposed by HECO in the current proceeding (HECO-1122).

Q. AS PART OF THE CONSUMER ADVOCATE'S DIRECT FILING IN THIS DOCKET, DID YOU PREPARE ANY ANALYSES OR ILLUSTRATIONS SHOWING HOW THE PENSION TRACKING MECHANISM WORKS?

A. Yes. Exhibit CA-302[20] was designed to examine how the pension tracking mechanism would handle two different scenarios:[21]

- Scenario 1 (page 2) assumed interim rates, effective July 2, 2009, would incorporate the revised NPPC forecast of about $31.5 million in base rates.[22]
- Scenario 2 (page 3) assumed interim rates would only include the original NPPC forecast of about $14.6 million.[23]

The pension tracking mechanism reconciles the difference between the amount of NPPC included in rates ("NPPC in Rates") and the actual amount of recorded NPPC ("Actual NPPC") quantified by annual actuarial studies. As these scenarios were intended to illustrate, if the amount of NPPC in Rates is higher than Actual NPPC during the rate effective period, the Company will record a regulatory liability under the pension tracking mechanism to be flowed back to

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20 For ease of reference, Exhibit CA-302 has been renamed as Exhibit CA-S303 and appended to this supplemental testimony.

21 See CA-T-3, pages 29-30, for a more detailed explanation of Scenarios 1 and 2.

22 Scenario 1 represents the Consumer Advocate approach on which CA Adjustments B-2, B-7 and C-14 are based.

23 For matters of simplification, Exhibit CA-302 does not incorporate related accumulated deferred income tax effects. The calculation of the impact on Scenario 1 ($31.5 million NPPC) is set forth on CA Adjustment B-7.

the benefit of ratepayers through a prospective five-year amortization and a rate base offset. If the amount of NPPC in Rates is lower than Actual NPPC during the rate effective period, the Company will record a regulatory asset that would be subject to symmetrical amortization and rate base treatments.

Inclusion of the higher actuarially determined amount of NPPC in current rates serves to reduce ratepayer exposure to a potentially substantial Regulatory Asset amortization in the next rate case. Depending on the direction of the economy in the remainder of 2009 and 2010, it is possible that the amount of NPPC in current rates could be too high. However, the pension tracking mechanism would produce a negative amortization to ratepayers in the next rate case, thereby protecting ratepayer interests. Conversely, if rates are set to include an artificially low amount of NPPC relative to current actuarial studies and future levels of actual NPPC, ratepayers would see higher future costs under the pension tracking mechanism.

The genesis of the perceived need for the pension tracking mechanism is that Actual NPPC can vary significantly from year to year, rate cases are not typically an annually recurring event, and the utility has limited ability to control the amount of Actual NPPC. Additionally, since the NPPC is affected by various factors, some of which are out of utility control, such as the gains or losses from the pension fund trust investments, the potential for unexpected volatility does exist.

Q. YOU PREVIOUSLY EXPLAINED THE DIFFERENCE BETWEEN NET PERIODIC PENSION COSTS, PENSION EXPENSE AND PENSION CONTRIBUTIONS. HOW DO PENSION CONTRIBUTIONS FACTOR INTO THE PENSION TRACKING MECHANISM?

A. A fundamental purpose of the pension tracking mechanism is that, over time, HECO will make contributions to the external pension trust funds in an amount equal to actual NPPC, barring Federal restrictions or limitations.[24] By design, the objective of the pension tracking mechanism is to ensure that actual NPPC is recovered through rates and that pension contributions equal actual NPPC. However, there is one transitional issue temporarily causing the amount of actual pension contributions to be less than actual NPPC.

Q. PLEASE EXPLAIN THAT TRANSITIONAL ISSUE.

A. As mentioned previously, the rate base treatment of the prepaid pension asset was litigated in HECO's 2005 rate case test year (Docket No. 04-0113), which the Commission ultimately excluded from rate base. In order to find a long-term remedy for the differences between the amounts of NPPC in Rates, actual NPPC and pension contributions, it was necessary for the pension tracking mechanism approved by the Commission on an interim basis in HECO's 2007 rate case test year (Docket No. 2006-0386) to address some resolution of the prepaid pension

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[24] See the Pension Tracking Mechanism previously filed as HECO-1122.

asset recorded on the Company's general ledger pursuant to generally accepted accounting principles. That resolution was to only require the Company to make contributions to the external pension trust fund equal to the minimum required amount under law until the prepaid pension asset balance is reduced to "zero." Once "zero" is reached, the pension tracking mechanism requires HECO to commence making pension contributions equal to actual NPPC. Based on information supplied by the Company in this proceeding,[25] it appears that the prepaid pension asset will likely reach "zero" in 2009. If this does occur, the pension contributions should equal the actual NPPC that is determined by the Company's actuarial consultant on a going forward basis.

Q. DOES THIS CONCLUDE YOUR SUPPLEMENTAL TESTIMONY?

A. Yes.

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25 See HECO-1124 and HECO responses to DOD-IR-83 and DOD-IR-101 (as supplemented March 20, 2009).

HAWAIIAN ELECTRIC COMPANY, INC.
Docket No. 2008-0083
HCEI-Related Costs Per Settlement Agreement
(000s)

					CA Adjustments Per Direct Testimony					Allowed By Settlement		
Line No.	CA Schedule	Description		Reference	Costs for Obtaining Approval	Costs for R&D Studies	Total Cost	Removed By Settlement	Total Allowed	Costs for Obtaining Approval	Consulting & Outside Svc Costs	Lease Costs
		(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
1	C-4	HCEI Implementation Studies (aka "Big Wind Studies")			$ -	$ (2,220)	$ (2,220)	$ (2,220)	$ -	$ -	$ -	$ -
2	C-4	PV Host Program	A/C 546	(i)	(200)	-	(200)	(120)	80	80		
3	C-4	Biofuel Agriculture Crop Research Phase 3	A/C 549	(a)(b)	-	(50)	(50)	-	50		50	
4	C-4	Biofuel Co-Firing Project Outside Services	A/C 549	(a)(c)	-	(649)	(649)	-	649		649	
5	C-4	Oahu Electric System Analysis	A/C 930.2	(a)	-	(677)	(677)	(677)	-	-	-	
6		Total for Schedule C-4			(200)	(3,596)	(3,796)	(3,017)	779	80	699	-
7	C-20	AMI T&D Outside Services	A/C 587	(d)(e)	(507)	-	(507)	(254)	253	253		
8	C-20	AMI R&D	A/C 930.2	(d)(f)	-	(611)	(611)	(244)	367		244	123
9		Total for Schedule C-20			(507)	(611)	(1,118)	(498)	620	253	244	123
10		**Total Per Settlement Agreement**			(707)	(4,207)	(4,914)	(3,515)	1,399	333	943	123
11	C-23	Feed-In Tariff Outside Services	A/C 921	(g)(h)	(92)	-	(92)	(138)	92	92		-
12		**Grand Total**			$ (799)	$ (4,207)	$ (5,006)	$ (3,653)	$ 1,491	$ 425	$ 943	$ 123

Footnotes:

(a) Source: HECO T-14 Update, p. 14.

(b) Crop research agreement with Hawaiian Agriculture Research Center. Also, see HECO T-14, pp. 37-39, and confidential HECO-WP-1407.
Settlement (Exhibit 1, p.21) allowed recovery of Biofuel crop research as part of an ongoing level of R&D expense included in base rates.

(c) Biofuel testing of Kahe steam boiler #3. Also, see HECO T-14, pp. 41-48, and responses to CA-IR-163, CA-IR-164, CA-IR-464 & CA-IR-483.
Settlement (Exhibit 1, p.21) allowed recovery of Biofuel co-firing project as part of an ongoing level of R&D expense included in base rates.

(d) Source: 2009 revised non-labor costs per CA-IR-178, Attachment 1. Also, see HECO T-8 (pp. 52-54), HECO T-14 (pp. 27-31), HECO T-14 Update (pp. 1-2 & 14), HECO T-8 Update (p. 5).

(e)

AMI T&D Outside Services:		2009 FCST	Amort. Period	Allowed	Removed
Regulatory Support - Legal	CA-IR-2	$ 74,630	2	$ 37,315	$ (37,315)
Regulatory Support - Consultant	CA-IR-2	351,892	2	175,946	(175,946)
ITS Project Management Consultant	CA-IR-178	80,000	2	40,000	(40,000)
Total		$ 506,522		$ 253,261	$ (253,261)

Settlement (Exhibit 1, p.20) provided for 2-year amortization of AMI legal, regulatory and outside consulting costs.
Source: HECO responses to CA-IR-2 (HECO T-8), Attachment 7B, p. 6; CA-IR-178, Attachment 1.

(f)

AMI R&D Costs:	2009 FCST	Amort. Period	Allowed	Removed
Vendor/Consultant (meter data management & IT suppo	$ 487,700	2	$ 243,850	$ (243,850)
Tower Gateway Base Station Lease	123,000		123,000	-
Total	$ 610,700		$ 366,850	$ (243,850)

Settlement (Exhibit 1, p.21) provided for 2-year amortization of AMI outside services costs and allowed TGB lease cost as annually recurring.
Source: HECO responses to CA-IR-158 & CA-IR-440(d).

(g)

Feed-In Tariff Outside Services:	2009 FCST	HELCO/MECO	HECO	Amort. Period	Allowed	Removed
Regulatory Support - Legal	$ 40,000	$ 8,000	$ 32,000	2	$ 16,000	$ (24,000)
Tariff Design & Policy - Consultant	123,000	24,600	98,400	2	49,200	(73,800)
Outside Engineering - Consultant	67,000	13,400	53,600	2	26,800	(40,200)
Total	$ 230,000	$ 46,000	$ 184,000		$ 92,000	$ (138,000)

Settlement (Exhibit 1, pp.20-21) provided for 2-year amortization of Feed-in Tariff consultant costs allocated to HECO.
Source: HECO T-11 Update (pp. 6-7 & Attachment 2, Note D); HECO response to CA-IR-343. Allocation: HELCO & MECO (20%), HECO (80%).

(h) The $138,000 of Feed-in Tariff costs removed by the settlement includes $46,000 allocated to HELCO and MECO. See Footnote (g).

(i)

PV Host Program:	2009 FCST	HELCO/MECO	HECO	Amort. Period	Allowed	Removed
Outside Services - Engineering System Integration	$ 75,000	$ 15,000	$ 60,000	2	$ 30,000	$ (45,000)
Outside Services - Consulting Site Support	25000	5,000	20,000	2	10,000	(15,000)
Outside Services - Consulting Program Design	75000	15,000	60,000	2	30,000	(45,000)
Outside Services - Legal Regulatory Support	25000	5,000	20,000	2	10,000	(15,000)
Total	$ 200,000	$ 40,000	$ 160,000		$ 80,000	$ (120,000)

Settlement (Exhibit 1, p.20) provided for 2-year amortization of PV Host costs allocated to HECO.
Source: HECO T-7 Update (p. 45); HECO response to CA-IR-296. Allocation: HELCO & MECO (20%), HECO (80%).

Witness: S. Carver

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2008-0083
DEPRECIATION & AMORTIZATION
FOR THE FORECAST 2009 TEST YEAR
(000's)

Exhibit CA-S301
Docket No. 2008-0883
Schedule C-22
Page 1 of 1
REVISED

LINE NO.	DESCRIPTION	REFERENCE	HECO UPDATE	CA PROPOSED	CA ADJUSTMENT
	(A)	(B)	(C)	(D)	(E)
1	Depreciation Expense	(a)(b)	$ 87,429	$ 86,783	$ (646)
2	Amortization Expense	(a)(b)	3,626	3,863	237
3	Additional Amortization -- Net Unrecovered	(a)(c)(d)(f)	1,924	1,099	(825)
4	Subtotal	(a)	92,979	91,745	(1,234)
5	Less: Depreciation on Vehicles	(a)(b)	(2,155)	(2,067)	88
6	Less: CIAC Amortization	(a)(e)	(9,383)	(9,335)	48
7	Add: Regulatory Asset Amortization	(a)	2,169	2,169	-
8	Less: Federal ITC Amortization	(a)	(644)	(644)	-
9	Total Depreciation & Amortization Expense		$ 82,966	$ 81,868	
10	**CA Adjustment to Depreciation & Amortization on Actual Investment at 12/31/2008**				**$ (1,098)**

Footnotes:

(a) Source: HECO T-14 Update (pp. 15, 20-22).

(b) Source: CA Proposed amount from HECO response to CA-IR-417.

(c) Per CA-IR-418, the Additional Amortization represents the net book value of assets subject to five-year vintage amortization that were retired from Company books on September 4, 2004, representing a stranded net investment. Decision & Order No. 21331 (Docket No. 02-0391) approved a Settlement Agreement between HECO and the Consumer Advocate commencing amortization on the effective date of the Commission's D&O (i.e., 9/4/04). This amortization sunsets two months after the interim scheduled for the pending docket for July 2, 2009. The amortization is nonrecurring and should be removed from proforma rates.

(d) According to CA-IR-418, the $1,924 should have been $2,198 for 2009 -- representing 8/12's of the 2008 annual amortization of $3,297 (HECO-WP-1401, p. 1).

(e) <u>CIAC Amortization for 2009:</u>

Vintage Amortizations through 2006		$ 8,263
2007 Vintage Amortization		694
2008 Vintage Amortization		
Actual 2008 Receipts	$ 11,314	
Actual 2008 Trans. from Cust. Adv	28	
Subtotal	11,342	
Amortization Period	30	378
Total 2009 CIAC Amortization		$ 9,335

Source: HECO T-14 Update (p. 23) & CA-IR-419.

(f) For settlement purposes, the CA agreed to reschedule the 2009 expiring amortization over two years, in order to reach closure on other outstanding issues. In CA-IR-418, HECO revised the 2009 amort from $1,924,000 to $2,198,000 -- accepted by CA.

Witness: S. Carver

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2008-0083
PENSION & OPEB COST ADJUSTMENT
FOR THE FORECAST 2009 TEST YEAR
(000's)

Exhibit CA-S302
Docket No. 2008-0083
Schedule C-14
Page 1 of 1
REVISED

LINE NO.	DESCRIPTION	REFERENCE	PENSION NPPC	OPEB NPBC	TOTAL
	(A)	(B)	(C)	(D)	(E)
1	Revised 2009 Pension (NPPC) / OPEB (NPBC) Cost	(a)	$ 31,489	$ 6,923	
2	Less: HECO 2009 Pension (NPPC) / OPEB (NPBC)	(b)	(14,623)	(5,224)	
3	Change in Total NPPC/NPBC		16,866	1,699	
4	Change in Regulatory Asset (Liability) Amortization	(c)	994	107	
5	Total		17,860	1,806	
6	Allocation to O&M Expense	(d)	71.41%	71.41%	
7	**CA Adjustment to Recognize Revised 2009 NPPC Forcast Provided by HECO Actuary**		$ 12,753	$ 1,289	$ 14,042

Footnotes:

(a) Source: HECO responses to DOD-IR-104 (Supplement 4/3/09), Attachment 4A.

(b) Source: HECO T-13 Update, Attachment 1 (line 1 for pensions & footnote 4 for OPEB).

(c) Change in Regulatory Asset (Liability) Amortization:

		NPPC	NPBC
CA Amortization (July-December 2009)	CA Adj. B-2	$ 384	$ (48)
HECO Amortization		(610)	(155)
Net Change in Amortization		$ 994	$ 107

Sources: CA Adjustment B-2 & HECO T-13 Update, Attachment 1.

(d) Allocation to O&M Expense:

Total Employee Benefits	$ 19,665	<revised to HECO T-13, Att. 1. rounding
Employee Benefits Transfer	(5,623)	<revised to HECO T-13, Att. 1. rounding
Employee Benefits Charged to O&M	$ 14,042	
O&M %	71.41%	

Source: HECO T-13 Update, Attachment 1.

(e) Revised NPBC Costs:

Updated OPEB NPBC	(a)	$ 6,942
Less: Executive Life Program (post retirement)		(19)
Revised NPBC Costs for Settlement Purposes		$ 6,923

HECO proposal to remove the Executive Life costs accepted by CA.

PENSION TRACKING MECHANISM
CONSUMER ADVOCATE
COMPARISON OF SCENARIOS 1 & 2
($000's)

		Scenario 1		Scenario 2		Difference With Scenario 2	
Line No.	Description	2009 TY Rate Base	2009 NPPC	2009 TY Rate Base	2009 NPPC	2009 TY Rate Base	2009 NPPC
	(A)	(B)	(C)	(D)	(E)	(F)	(G)
	Average 2009 TY Rate Base:						
1	Regulatory Asset	$ 3,100		$ 7,316			
2	Regulatory Liability 1	(2,898)		(2,898)			
3	Total	$ 202		$ 4,418		$ 4,216	
	Annual Amortization:						
4	Regulatory Asset		$ 1,378		$ 1,378		$ -
5	Regulatory Liability 1		(610)		(610)		-
6	Total		$ 768		$ 768		$ -
7	Interim NPPC		$ 31,488		$ 14,623		$ (16,865)
8	Final D&O NPPC		$ 31,488		$ 14,623		$ (16,865)

PENSION TRACKING MECHANISM
CONSUMER ADVOCATE – SCENARIO 1
RECOGNITION OF REVISED 2009 NPPC FORECAST
($000's)

Line No.	Description	NPPC In Rates	Actual NPPC	Contribution	Prepaid Pension Asset Current Year	Prepaid Pension Asset Cumulative	Regulatory Asset Current Year	Regulatory Asset Amortization	Regulatory Asset Cumulative	Regulatory Liability 1 Current Year	Regulatory Liability 1 Amortization	Regulatory Liability 1 Cumulative	Regulatory Liability 2 Current Year	Regulatory Liability 2 Cumulative
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
	Assumptions:													
1	2007 Amounts	$ 17,711	$ 17,711											
2	2008 Amounts	$ 17,711	$ 14,660											
3	2009 Amounts	$ 31,488	$ 31,488											
4	Interim, Dkt. 2006-0386	10/22/07												
5	Initial Start Year-End		12/31/07											
6	Year End Prior to Test Year		12/31/08											
7	Interim, Dkt. 2008-0083		7/2/09											
8	Final D&O, Dkt. 2008-0083		12/31/09											
	Calendar Year													
9	2007 (beg. 10/22/07)	$ 3,397	$ 3,397	$ -	$ (3,397)	$ (3,397)	$ -		$ -	$ -		$ -	$ -	$ -
10	2008	17,711	14,660	-	(14,660)	(18,057)	-		-	(3,051)		(3,051)	-	-
11	2009 (Jan-Jun)	8,856	15,744	-	(15,744)	(33,801)	6,889		6,889	-		(3,051)	-	-
12	2009 (Jul-Dec)	15,744	15,744	8,218	(7,526)	(41,327)	-	$ (689)	6,200	-	$ 305	(2,746)	-	-
13	2010													
14	Totals	$ 45,707	$ 49,545	$ 8,218	$ (41,327)		$ 6,889	$ (689)		$ (3,051)	$ 305		$ -	
		(a)	(a)	(a)	(b)	(b)	(c)	(c)		(d)	(d)			
15	Average 2009 TY Rate Base								$ 3,100			$ (2,898)		
16	2009 -- Interim Amortization	(c) (d)						$ 689			$ (305)			
17	2009 -- Annual Amortization	(e)						$ 1,378			$ (610)			
18	Interim NPPC	$ 31,488												
19	Final D&O NPPC	$ 31,488												

Footnotes:
(a) Sources: HECO-1124, CA-IR-243, DOD-IR-83 & DOD-IR-101 (Supplemental 3/20/09).
(b) Pursuant to Procedure Section 2 of the Pension Tracking Mechanism, HECO is only required to make pension fund contributions equal to the minimum required under law -- until the recorded pension asset balance is reduced to "zero". Thereafter, pension contributions shall equal Actual NPPC, except when limited by minimum contribution or IRC maximum requirements. The "negative" prepaid pension asset of $(17,493) represents the cumulative reduction to the prior recorded prepaid pension asset balance.
(c) The Regulatory Asset represents the excess of Actual NPPC over NPPC in Rates. The average test year balance is included in rate base, net of the amortization commencing with interim rate change – amount represents a test year prorate any only applies to determine rate base ending balance..
(d) The Regulatory Liability 1 represents the excess of NPPC in Rates over Actual NPPC. The average test year balance is included in rate base, net of the amortization commencing with interim rate change -- amount represents a test year prorate any only applies to determine rate base ending balance..
(e) The Annual Amortization is the amount included in Final D&O, representing a full 12 months.

PENSION TRACKING MECHANISM
CONSUMER ADVOCATE – SCENARIO 2
RECOGNITION OF ORIGINAL 2009 NPPC FORECAST
($000's)

Line No.	Description (A)	NPPC In Rates (B)	Actual NPPC (C)	Contribution (D)	Prepaid Pension Asset Current Year (E)	Prepaid Pension Asset Cumulative (F)	Regulatory Asset Current Year (G)	Regulatory Asset Amortization (H)	Regulatory Asset Cumulative (I)	Regulatory Liability 1 Current Year (J)	Regulatory Liability 1 Amortization (K)	Regulatory Liability 1 Cumulative (L)	Regulatory Liability 2 Current Year (M)	Regulatory Liability 2 Cumulative (N)
	Assumptions:													
1	2007 Amounts	$ 17,711	$ 17,711											
2	2008 Amounts	$ 17,711	$ 14,660											
3	2009 Amounts	$ 14,623	$ 31,488											
4	Interim, Dkt. 2006-0386	10/22/07												
5	Initial Start Year-End		12/31/07											
6	Year End Prior to Test Year		12/31/08											
7	Interim, Dkt. 2008-0083		7/2/09											
8	Final D&O, Dkt. 2008-0083		12/31/09											
	Calendar Year													
9	2007 (beg. 10/22/07)	$ 3,397	$ 3,397	$ -	$ (3,397)	$ (3,397)	$ -		$ -	$ -		$ -	$ -	$ -
10	2008	17,711	14,660	-	(14,660)	(18,057)	-		-	(3,051)		(3,051)	-	-
11	2009 (Jan-Jun)	8,856	15,744	-	(15,744)	(33,801)	6,889		6,889	-		(3,051)	-	-
12	2009 (Jul-Dec)	7,312	15,744	8,218	(7,526)	(41,327)	8,433	$ (689)	14,632	-	$ 305	(2,746)	-	-
13	2010													
14	Totals	$ 37,275	$ 49,545	$ 8,218	$ (41,327)		$ 15,321	$ (689)		$ (3,051)	$ 305		$ -	
		(a)	(a)	(a)	(b)	(b)	(c)	(c)		(d)	(d)			
15	Average 2009 TY Rate Base								$ 7,316			$ (2,898)		
16	2009 -- Interim Amortization	(c) (d)						$ 689			$ (305)			
17	2009 -- Annual Amortization	(e)						$ 1,378			$ (610)			
18	Interim NPPC	$ 14,623												
19	Final D&O NPPC	$ 14,623												

Footnotes:

(a) Sources: HECO-1124, CA-IR-243, DOD-IR-83 & DOD-IR-101 (Supplemental 3/20/09).

(b) Pursuant to Procedure Section 2 of the Pension Tracking Mechanism, HECO is only required to make pension fund contributions equal to the minimum required under law -- until the recorded pension asset balance is reduced to "zero". Thereafter, pension contributions shall equal Actual NPPC, except when limited by minimum contribution or IRC maximum requirements. The "negative" prepaid pension asset of $(17,493) represents the cumulative reduction to the prior recorded prepaid pension asset balance.

(c) The Regulatory Asset represents the excess of Actual NPPC over NPPC in Rates. The average test year balance is included in rate base, net of the amortization commencing with interim rate change -- amount represents a test year prorate any only applies to determine rate base ending balance..

(d) The Regulatory Liability 1 represents the excess of NPPC in Rates over Actual NPPC. The average test year balance is included in rate base, net of the amortization commencing with interim rate change -- amount represents a test year prorate any only applies to determine rate base ending balance..

(e) The Annual Amortization is the amount included in Final D&O, representing a full 12 months.

ST-4

D. PARCELL

CA-ST-4
DOCKET NO. 2008-0083

SUPPLEMENTAL TESTIMONY AND EXHIBITS

OF

DAVID C. PARCELL

ON BEHALF OF
THE DIVISION OF CONSUMER ADVOCACY

SUBJECT: RATE OF RETURN

TABLE OF CONTENTS

SUPPLEMENTAL TESTIMONY OF DAVID C. PARCELL

I. INTRODUCTION.

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is David C. Parcell. I am President and Senior Economist of Technical Associates, Inc. My business address is Suite 601, 1051 East Cary Street, Richmond, Virginia 23219.

Q. ARE YOU THE SAME DAVID C. PARCELL WHO FILED DIRECT TESTIMONY ON BEHALF OF THE CONSUMER ADVOCATE ON APRIL 17, 2009?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL TESTIMONY?

A. The first purpose of my supplemental testimony is to indicate the extent to which the Commission's Interim Decision and Order, dated July 2, 2009, impacts my testimony and recommendations. My supplemental testimony is also designed to present an update to the exhibits submitted in my direct testimony. I have updated the exhibits for which more current data is available as of early July, 2009. As will be discussed later, I am introducing one additional exhibit, CA-S-417, but for the Commission's convenience, I am including a complete set of all exhibits that were filed with my direct testimony.

In addition to the updates of my exhibits, I have prepared a "modification" to my CA-408 to reflect the use of "spot" dividend yields, rather than 3-month average yields as shown in my direct testimony. This schedule is presented as CA-S-408-M.

II. <u>IMPACT OF INTERIM DECISION.</u>

Q. ON JULY 2, 2009, THE COMMISSION ISSUED AN INTERIM DECISION AND ORDER IN THIS PROCEEDING. DOES THIS INTERIM DECISION AND ORDER IMPACT YOUR TESTIMONY AND RECOMMENDATIONS?

A. The Commission's Interim Decision and Order approved in part and denied in part the proposed stipulated settlement ("Stipulation") of most of the issues in this proceeding. It is my understanding that the Stipulation incorporated an interim cost of equity of 10.5 percent, with the understanding that the cost of equity would be litigated in this proceeding in a hearing before the Commission. To this extent, the Commission's Interim Decision and Order does not impact my analyses and recommendation although, as noted below, I have updated my cost of capital analyses.

The Commission's Interim Decision and Order also expressly excluded any HCEI-related costs from interim rates. It is my understanding that these costs, including proposals for decoupling supported by HECO and the Consumer Advocate in Docket No. 2008-0274, are not to be included in rates until the Commission has filed a decision and order on those HCEI-related items.

In my direct testimony, on pages 20-23 and 52-54, I indicated that the HCEI proposals, including decoupling, are risk-reducing to HECO and have the effect of transferring a portion of the Company's risks from its shareholders to its customers. I recommended that, should the various proposals be adopted, the cost of equity be reduced by 50 basis points. On page 4, I indicated that the bottom of my 9.5 percent to 10.5 percent cost of equity range should be adopted for the purposes of the instant rate proceeding if these HCEI-related proposals were adopted.

Q. HOW IS YOUR RECOMMENDATION INFLUENCED BY THE COMMISSION'S INTERIM DECISION AND ORDER?

A. If the HCEI-related programs and decoupling are "off the table," I now recommend that the mid-point of my cost of equity range be adopted.

III. UPDATES TO COST OF EQUITY ANALYSES.

Q. PLEASE EXPLAIN WHY YOU HAVE UPDATED YOUR EXHIBITS.

A. I have updated my exhibits in order to provide the Commission with the most up-to-date information available as of this time. This is proper in order for the Commission to have the most current information available at the time of the hearing.

In addition, HECO witness Morin has stated (HECO RT-19, at pp. 52 and 54-56) that I have used "stale" information in my cost of capital analyses. My updates should address this particular criticism.

I have provided a "modification" of my DCF analyses to also answer the criticism of HECO witness Morin that I have used "stale" information. He criticizes my DCF analyses (HECO RT-19, at pp. 52 and 54-56) for using 3-month average stock prices in the yield component. My CA-S-408-M uses "spot" stock prices as of July 6, 2009, which Dr. Morin suggests is proper. Even though I do not agree with his criticism, I have prepared CA-S-408-M to answer his point.

Q. HOW ARE YOUR UPDATED AND MODIFIED EXHIBITS LABELED?

A. As mentioned earlier, I am providing a complete set of my exhibits attached to this testimony, but not all of those exhibits are necessarily updated. My updated exhibits contain the same exhibit numbers as my direct testimony, except they are labeled "updated," which will be notated in the index on the upper right hand of the page. My "modified" CA-S-408-M is labeled "modified."

Q. HAVE YOU PREPARED A NEW EXHIBIT TO SUMMARIZE THE IMPACTS OF THE UPDATES AND MODIFICATIONS ON YOUR ORIGINAL COST OF CAPITAL ANALYSES?

A. Yes, I have. This is labeled as CA-S-417. As this exhibit illustrates, the net effect of "updating" and "modifying" my DCF analyses is no change in my conclusions. The same is true for my updated CAPM analyses.

Q. WHAT IS THE IMPACT OF YOUR UPDATES AND MODIFICATIONS?

A. The overall impact is to leave my original cost of equity recommendation of 9.5 to 10.5 unchanged.

Q. DOES THIS CONCLUDE YOUR SUPPLEMENTAL TESTIMONY?

A. Yes, it does.

HAWAIIAN ELECTRIC COMPANY
TOTAL COST OF CAPITAL

ITEM	PERCENT		COST RATE			WEIGHTED COST	
Short-Term Debt	0.00%					0.00%	
Long-Term Debt	40.76%		5.81%			2.37%	
Hybrid Securities	1.96%		7.41%			0.15%	
Preferred Stock	1.46%		5.48%			0.08%	
Common Equity	55.81%	9.50%		10.50%	5.30%		5.86%
Total	99.99%				**7.90%**		**8.45%**

ECONOMIC INDICATORS

YEAR	REAL GDP GROWTH	IND PROD GROWTH	UNEMP RATE	CPI	PPI
			1975 - 1982 Cycle		
1975	-1.1%	-8.9%	8.5%	7.0%	6.6%
1976	5.4%	10.8%	7.7%	4.8%	3.7%
1977	5.5%	5.9%	7.0%	6.8%	6.9%
1978	5.0%	5.7%	6.0%	9.0%	9.2%
1979	2.8%	4.4%	5.8%	13.3%	12.8%
1980	-0.2%	-1.9%	7.0%	12.4%	11.8%
1981	1.8%	1.9%	7.5%	8.9%	7.1%
1982	-2.1%	-4.4%	9.5%	3.8%	3.6%
			1983 - 1991 Cycle		
1983	4.0%	3.7%	9.5%	3.8%	0.6%
1984	6.8%	9.3%	7.5%	3.9%	1.7%
1985	3.7%	1.7%	7.2%	3.8%	1.8%
1986	3.1%	0.9%	7.0%	1.1%	-2.3%
1987	2.9%	4.9%	6.2%	4.4%	2.2%
1988	3.8%	4.5%	5.5%	4.4%	4.0%
1989	3.5%	1.8%	5.3%	4.6%	4.9%
1990	1.8%	-0.2%	5.6%	6.1%	5.7%
1991	-0.5%	-2.0%	6.8%	3.1%	-0.1%
			1992 - 2001 Cycle		
1992	3.0%	3.1%	7.5%	2.9%	1.6%
1993	2.7%	3.3%	6.9%	2.7%	0.2%
1994	4.0%	5.4%	6.1%	2.7%	1.7%
1995	2.5%	4.8%	5.6%	2.5%	2.3%
1996	3.7%	4.3%	5.4%	3.3%	2.8%
1997	4.5%	7.2%	4.9%	1.7%	-1.2%
1998	4.2%	6.1%	4.5%	1.6%	0.0%
1999	4.5%	4.3%	4.2%	2.7%	2.9%
2000	3.7%	4.2%	4.0%	3.4%	3.6%
2001	0.8%	-3.4%	4.7%	1.6%	-1.6%
			Current Cycle		
2002	1.6%	-0.1%	5.8%	2.4%	1.2%
2003	2.5%	1.3%	6.0%	1.9%	4.0%
2004	3.9%	2.5%	5.5%	3.3%	4.2%
2005	2.9%	3.3%	5.1%	3.4%	5.4%
2006	2.8%	2.3%	4.6%	2.5%	1.1%
2007	2.0%	1.5%	4.6%	4.1%	6.2%
2008	1.1%	-2.2%	5.8%	0.1%	-0.9%

Source: Council of Economic Advisors, Economic Indicators, various issues.

ECONOMIC INDICATORS

YEAR	REAL GDP GROWTH	IND PROD GROWTH	UNEMP RATE	CPI	PPI
2002					
1st Qtr.	2.7%	-3.8%	5.6%	2.8%	4.4%
2nd Qtr.	2.2%	-1.2%	5.9%	0.9%	-2.0%
3rd Qtr.	2.4%	0.8%	5.8%	2.4%	1.2%
4th Qtr.	0.2%	1.4%	5.9%	1.6%	0.4%
2003					
1st Qtr.	1.2%	1.1%	5.8%	4.8%	5.6%
2nd Qtr.	3.5%	-0.9%	6.2%	0.0%	-0.5%
3rd Qtr.	7.5%	-0.9%	6.1%	3.2%	3.2%
4th Qtr.	2.7%	1.5%	5.9%	-0.3%	2.8%
2004					
1st Qtr.	3.0%	2.8%	5.6%	5.2%	5.2%
2nd Qtr.	3.5%	4.9%	5.6%	4.4%	4.4%
3rd Qtr.	3.6%	4.6%	5.4%	0.8%	0.8%
4th Qtr.	2.5%	4.3%	5.4%	3.6%	7.2%
2005					
1st Qtr.	3.0%	3.8%	5.3%	4.4%	5.6%
2nd Qtr.	2.6%	3.0%	5.1%	1.6%	-0.4%
3rd Qtr.	3.8%	2.7%	5.0%	8.8%	14.0%
4th Qtr.	1.3%	2.9%	4.9%	-2.0%	4.0%
2006					
1st Qtr.	4.8%	3.4%	4.7%	4.8%	-0.2%
2nd Qtr.	2.7%	4.5%	4.6%	4.8%	5.6%
3rd Qtr.	0.8%	5.2%	4.7%	0.4%	-4.4%
4th Qtr.	1.5%	3.5%	4.5%	0.0%	3.6%
2007					
1st Qtr.	0.1%	2.5%	4.5%	4.8%	6.4%
2nd Qtr.	4.8%	1.6%	4.5%	5.2%	6.8%
3rd Qtr.	4.8%	1.8%	4.6%	1.2%	1.2%
4th Qtr.	-0.2%	1.7%	4.8%	5.6%	12.8%
2008					
1st Qtr.	0.9%	1.8%	4.9%	2.8%	9.6%
2nd Qtr.	2.8%	-0.4%	5.4%	7.6%	14.0%
3rd Qtr.	-0.5%	-3.2%	6.1%	2.8%	-0.4%
4th Qtr.	-6.3%	-6.6%	6.9%	-13.2%	-28.4%
2009					
1st Qtr.	-6.1%	-11.8%	8.1%	2.4%	-1.2%

Source: Council of Economic Advisors, Economic Indicators, various issues.

INTEREST RATES

YEAR	PRIME RATE	US TREAS T BILLS 3 MONTH	US TREAS T BONDS 10 YEAR	UTILITY BONDS Aaa	UTILITY BONDS Aa	UTILITY BONDS A	UTILITY BONDS Baa
			1975 - 1982 Cycle				
1975	7.86%	5.84%	7.99%	9.03%	9.44%	10.09%	10.96%
1976	6.84%	4.99%	7.61%	8.63%	8.92%	9.29%	9.82%
1977	6.83%	5.27%	7.42%	8.19%	8.43%	8.61%	9.06%
1978	9.06%	7.22%	8.41%	8.87%	9.10%	9.29%	9.62%
1979	12.67%	10.04%	9.44%	9.86%	10.22%	10.49%	10.96%
1980	15.27%	11.51%	11.46%	12.30%	13.00%	13.34%	13.95%
1981	18.89%	14.03%	13.93%	14.64%	15.30%	15.95%	16.60%
1982	14.86%	10.69%	13.00%	14.22%	14.79%	15.86%	16.45%
			1983 - 1991 Cycle				
1983	10.79%	8.63%	11.10%	12.52%	12.83%	13.66%	14.20%
1984	12.04%	9.58%	12.44%	12.72%	13.66%	14.03%	14.53%
1985	9.93%	7.48%	10.62%	11.68%	12.06%	12.47%	12.96%
1986	8.33%	5.98%	7.68%	8.92%	9.30%	9.58%	10.00%
1987	8.21%	5.82%	8.39%	9.52%	9.77%	10.10%	10.53%
1988	9.32%	6.69%	8.85%	10.05%	10.26%	10.49%	11.00%
1989	10.87%	8.12%	8.49%	9.32%	9.56%	9.77%	9.97%
1990	10.01%	7.51%	8.55%	9.45%	9.65%	9.86%	10.06%
1991	8.46%	5.42%	7.86%	8.85%	9.09%	9.36%	9.55%
			1992 - 2001 Cycle				
1992	6.25%	3.45%	7.01%	8.19%	8.55%	8.69%	8.86%
1993	6.00%	3.02%	5.87%	7.29%	7.44%	7.59%	7.91%
1994	7.15%	4.29%	7.09%	8.07%	8.21%	8.31%	8.63%
1995	8.83%	5.51%	6.57%	7.68%	7.77%	7.89%	8.29%
1996	8.27%	5.02%	6.44%	7.48%	7.57%	7.75%	8.16%
1997	8.44%	5.07%	6.35%	7.43%	7.54%	7.60%	7.95%
1998	8.35%	4.81%	5.26%	6.77%	6.91%	7.04%	7.26%
1999	8.00%	4.66%	5.65%	7.21%	7.51%	7.62%	7.88%
2000	9.23%	5.85%	6.03%	7.88%	8.06%	8.24%	8.36%
2001	6.91%	3.45%	5.02%	7.47%	7.59%	7.78%	8.02%
			Current Cycle				
2002	4.67%	1.62%	4.61%		7.19%	7.37%	8.02%
2003	4.12%	1.02%	4.01%		6.40%	6.58%	6.84%
2004	4.34%	1.38%	4.27%		6.04%	6.16%	6.40%
2005	6.19%	3.16%	4.29%		5.44%	5.65%	5.93%
2006	7.96%	4.73%	4.80%		5.84%	6.07%	6.32%
2007	8.05%	4.41%	4.63%		5.94%	6.07%	6.33%
2008	5.09%	1.48%	3.66%		6.18%	6.53%	7.25%

Sources: Council of Economic Advisors, Economic Indicators; Moody's Bond Record; Federal Reserve Bulletin; various issues.

INTEREST RATES

YEAR	PRIME RATE	US TREAS T BILLS 3 MONTH	US TREAS T BONDS 10 YEAR	UTILITY BONDS Aaa	UTILITY BONDS Aa	UTILITY BONDS A	UTILITY BONDS Baa
2003							
Jan	4.25%	1.17%	4.05%		6.87%	7.06%	7.47%
Feb	4.25%	1.16%	3.90%		6.66%	6.93%	7.17%
Mar	4.25%	1.13%	3.81%		6.56%	6.79%	7.05%
Apr	4.25%	1.14%	3.96%		6.47%	6.64%	6.94%
May	4.25%	1.08%	3.57%		6.20%	6.36%	6.47%
June	4.00%	0.95%	3.33%		6.12%	6.21%	6.30%
July	4.00%	0.90%	3.98%		6.37%	6.57%	6.67%
Aug	4.00%	0.96%	4.45%		6.48%	6.78%	7.08%
Sept	4.00%	0.95%	4.27%		6.30%	6.56%	6.87%
Oct	4.00%	0.93%	4.29%		6.28%	6.43%	6.79%
Nov	4.00%	0.94%	4.30%		6.26%	6.37%	6.69%
Dec	4.00%	0.90%	4.27%		6.18%	6.27%	6.61%
2004							
Jan	4.00%	0.89%	4.15%		6.06%	6.15%	6.47%
Feb	4.00%	0.92%	4.08%		6.10%	6.15%	6.28%
Mar	4.00%	0.94%	3.83%		5.93%	5.97%	6.12%
Apr	4.00%	0.94%	4.35%		6.33%	6.35%	6.46%
May	4.00%	1.04%	4.72%		6.66%	6.62%	6.75%
June	4.00%	1.27%	4.73%		6.30%	6.46%	6.84%
July	4.25%	1.35%	4.50%		6.09%	6.27%	6.67%
Aug	4.50%	1.48%	4.28%		5.95%	6.14%	6.45%
Sept	4.75%	1.65%	4.13%		5.79%	5.98%	6.27%
Oct	4.75%	1.75%	4.10%		5.74%	5.94%	6.17%
Nov	5.00%	2.06%	4.19%		5.79%	5.97%	6.16%
Dec	5.25%	2.20%	4.23%		5.78%	5.92%	6.10%
2005							
Jan	5.25%	2.32%	4.22%		5.68%	5.78%	5.95%
Feb	5.50%	2.53%	4.17%		5.55%	5.61%	5.76%
Mar	5.75%	2.75%	4.50%		5.76%	5.83%	6.01%
Apr	5.75%	2.79%	4.34%		5.56%	5.64%	5.95%
May	6.00%	2.86%	4.14%		5.39%	5.53%	5.88%
June	6.25%	2.99%	4.00%		5.05%	5.40%	5.70%
July	6.25%	3.22%	4.18%		5.18%	5.51%	5.81%
Aug	6.50%	3.45%	4.26%		5.23%	5.50%	5.80%
Sept	6.75%	3.47%	4.20%		5.27%	5.52%	5.83%
Oct	6.75%	3.70%	4.46%		5.50%	5.79%	6.08%
Nov	7.00%	3.90%	4.54%		5.59%	5.88%	6.19%
Dec	7.25%	3.89%	4.47%		5.55%	5.80%	6.14%
2006							
Jan	7.50%	4.20%	4.42%		5.50%	5.75%	6.06%
Feb	7.50%	4.41%	4.57%		5.55%	5.82%	6.11%
Mar	7.75%	4.51%	4.72%		5.71%	5.98%	6.26%
Apr	7.75%	4.59%	4.99%		6.02%	6.29%	6.54%
May	8.00%	4.72%	5.11%		6.16%	6.42%	6.59%
June	8.25%	4.79%	5.11%		6.16%	6.40%	6.61%
July	8.25%	4.96%	5.09%		6.13%	6.37%	6.61%
Aug	8.25%	4.98%	4.88%		5.97%	6.20%	6.43%
Sept	8.25%	4.82%	4.72%		5.81%	6.00%	6.26%
Oct	8.25%	4.89%	4.73%		5.80%	5.98%	6.24%
Nov	8.25%	4.95%	4.60%		5.61%	5.80%	6.04%
Dec	8.25%	4.85%	4.56%		5.62%	5.81%	6.05%
2007							
Jan	8.25%	4.98%	4.76%		5.78%	5.96%	6.16%
Feb	8.25%	5.02%	4.72%		5.73%	5.90%	6.10%
Mar	8.25%	4.97%	4.56%		5.66%	5.85%	6.10%
Apr	8.25%	4.88%	4.69%		5.83%	5.97%	6.24%
May	8.25%	4.77%	4.75%		5.86%	5.99%	6.23%
June	8.25%	4.63%	5.10%		6.18%	6.30%	6.54%
July	8.25%	4.84%	5.00%		6.11%	6.25%	6.49%
Aug	8.25%	4.34%	4.67%		6.11%	6.24%	6.51%
Sept	7.75%	4.01%	4.52%		6.10%	6.18%	6.45%
Oct	7.50%	3.97%	4.53%		6.04%	6.11%	6.36%
Nov	7.50%	3.49%	4.15%		5.87%	5.97%	6.27%
Dec	7.25%	3.08%	4.10%		6.03%	6.16%	6.51%
2008							
Jan	6.00%	2.86%	3.74%		5.87%	6.02%	6.35%
Feb	6.00%	2.21%	3.74%		6.04%	6.21%	6.60%
Mar	5.25%	1.38%	3.51%		5.99%	6.21%	6.68%
Apr	5.00%	1.32%	3.68%		5.99%	6.29%	6.82%
May	5.00%	1.71%	3.88%		6.07%	6.27%	6.79%
June	5.00%	1.90%	4.10%		6.19%	6.38%	6.93%
July	5.00%	1.72%	4.01%		6.13%	6.40%	6.97%
Aug	5.00%	1.79%	3.89%		6.09%	6.37%	6.98%
Sept	5.00%	1.46%	3.69%		6.13%	6.49%	7.15%
Oct	4.00%	0.84%	3.81%		6.95%	7.56%	8.58%
Nov	4.00%	0.30%	3.53%		6.83%	7.60%	8.98%
Dec	3.25%	0.04%	2.42%		5.93%	6.54%	8.13%
2008							
Jan	3.25%	0.12%	2.52%		6.01%	6.39%	7.90%
Feb	3.25%	0.31%	2.87%		6.11%	6.30%	7.74%
Mar	3.25%	0.25%	2.82%		6.14%	6.42%	8.00%
Apr	3.25%	0.17%	2.93%		6.20%	6.48%	8.03%
May	3.25%	0.15%	3.29%		6.23%	6.49%	7.76%
June	3.25%	0.18%	3.72%		6.13%	6.20%	7.30%

Sources: Council of Economic Advisors, Economic Indicators; Moody's Bond Record; Federal Reserve Bulletin; various issues.

STOCK PRICE INDICATORS

YEAR	S&P Composite	Nasdaq Composite	DJIA	S&P D/P	S&P E/P
		1975 - 1982 Cycle			
1975			802.49	4.31%	9.15%
1976			974.92	3.77%	8.90%
1977			894.63	4.62%	10.79%
1978			820.23	5.28%	12.03%
1979			844.40	5.47%	13.46%
1980			891.41	5.26%	12.66%
1981			932.92	5.20%	11.96%
1982			884.36	5.81%	11.60%
		1983 - 1991 Cycle			
1983			1,190.34	4.40%	8.03%
1984			1,178.48	4.64%	10.02%
1985			1,328.23	4.25%	8.12%
1986			1,792.76	3.49%	6.09%
1987			2,275.99	3.08%	5.48%
1988			2,060.82	3.64%	8.01%
1989	322.84		2,508.91	3.45%	7.41%
1990	334.59		2,678.94	3.61%	6.47%
1991	376.18	491.69	2,929.33	3.24%	4.79%
		1992 - 2001 Cycle			
1992	415.74	599.26	3,284.29	2.99%	4.22%
1993	451.21	715.16	3,522.06	2.78%	4.46%
1994	460.42	751.65	3,793.77	2.82%	5.83%
1995	541.72	925.19	4,493.76	2.56%	6.09%
1996	670.50	1,164.96	5,742.89	2.19%	5.24%
1997	873.43	1,469.49	7,441.15	1.77%	4.57%
1998	1,085.50	1,794.91	8,625.52	1.49%	3.46%
1999	1,327.33	2,728.15	10,464.88	1.25%	3.17%
2000	1,427.22	3,783.67	10,734.90	1.15%	3.63%
2001	1,194.18	2,035.00	10,189.13	1.32%	2.95%
		Current Cycle			
2002	993.94	1,539.73	9,226.43	1.61%	2.92%
2003	965.23	1,647.17	8,993.59	1.77%	3.84%
2004	1,130.65	1,986.53	10,317.39	1.72%	4.89%
2005	1,207.23	2,099.32	10,547.67	1.83%	5.36%
2006	1,310.46	2,263.41	11,408.67	1.87%	5.78%
2007	1,477.19	2,578.47	13,169.98	1.86%	5.29%
2008	1,220.04	2,161.65	11,252.62	2.37%	3.84%

Source: Council of Economic Advisors, Economic Indicators, various issues.

STOCK PRICE INDICATORS

YEAR	S&P Composite	Nasdaq Composite	DJIA	S&P D/P	S&P E/P
2002					
1st Qtr.	1,131.56	1,879.85	10,105.27	1.39%	2.15%
2nd Qtr.	1,068.45	1,641.53	9,912.70	1.49%	2.70%
3rd Qtr.	894.65	1,308.17	8,487.59	1.76%	3.68%
4th Qtr.	887.91	1,346.07	8,400.17	1.79%	3.14%
2003					
1st Qtr.	860.03	1,350.44	8,122.83	1.89%	3.57%
2nd Qtr.	938.00	1,521.92	8,684.52	1.75%	3.55%
3rd Qtr.	1,000.50	1,765.96	9,310.57	1.74%	3.87%
4th Qtr.	1,056.42	1,934.71	9,856.44	1.69%	4.38%
2004					
1st Qtr.	1,133.29	2,041.95	10,488.43	1.64%	4.62%
2nd Qtr.	1,122.87	1,984.13	10,289.04	1.71%	4.92%
3rd Qtr.	1,104.15	1,872.90	10,129.85	1.79%	5.18%
4th Qtr.	1,162.07	2,050.22	10,362.25	1.75%	4.83%
2005					
1st Qtr.	1,191.98	2,056.01	10,648.48	1.77%	5.11%
2nd Qtr.	1,181.65	2,012.24	10,382.35	1.85%	5.32%
3rd Qtr.	1,225.91	2,144.61	10,532.24	1.83%	5.42%
4th Qtr.	1,262.07	2,246.09	10,827.79	1.86%	5.60%
2006					
1st Qtr.	1,283.04	2,287.97	10,996.04	1.85%	5.61%
2nd Qtr.	1,281.77	2,240.46	11,188.84	1.90%	5.86%
3rd Qtr.	1,288.40	2,141.97	11,274.49	1.91%	5.88%
4th Qtr.	1,389.48	2,390.26	12,175.30	1.81%	5.75%
2007					
1st Qtr.	1,425.30	2,444.85	12,470.97	1.84%	5.85%
2nd Qtr.	1,496.43	2,552.37	13,214.26	1.82%	5.65%
3rd Qtr.	1,490.81	2,609.68	13,488.43	1.86%	5.15%
4th Qtr.	1,494.09	2,701.59	13,502.95	1.91%	4.51%
2008					
1st Qtr.	1,350.19	2,332.92	12,383.86	2.11%	4.57%
2nd Qtr.	1,371.65	2,426.26	12,508.59	2.10%	4.01%
3rd Qtr.	1,251.94	2,290.87	11,322.40	2.29%	3.94%
4th Qtr.	909.80	1,599.64	8,795.61	2.98%	1.65%
2009					
1st Qtr.	809.31	1,485.14	7,774.06	3.00%	0.87%

Source: Council of Economic Advisors, Economic Indicators, various issues.

HAWAIIAN ELECTRIC INDUSTRIES, INC.
SEGMENT FINANCIAL INFORMATION
2006 - 2008
($000)

Segment	Revenues	Net Income	Capital Expenditures	Assets
		2006		
Electric Utility	$2,054,890 83.5%	$74,947 69.4%	$195,072 92.7%	$3,063,134 31.0%
Bank	$408,365 16.6%	$55,782 51.6%	$14,927 7.1%	$6,808,499 68.8%
Other	-$2,351 -0.1%	-$22,728 -21.0%	$530 0.3%	$19,576 0.2%
Hawaiian Electric Industries, Inc. (Consolidated)	$2,460,904	$108,001	$210,529	$9,891,209
		2007		
Electric Utility	$2,106,314 83.0%	$52,156 61.5%	$209,821 96.1%	$3,423,888 33.3%
Bank	$425,495 16.8%	$53,107 62.6%	$7,866 3.6%	$6,861,493 66.7%
Other	$4,609 0.2%	-$20,484 -24.2%	$610 0.3%	$8,535 0.1%
Hawaiian Electric Industries, Inc. (Consolidated)	$2,536,418	$84,779	$218,297	$10,293,916
		2008		
Electric Utility	$2,860,350 88.9%	$91,975 101.9%	$278,476 98.7%	$3,856,109 41.5%
Bank	$358,553 11.1%	$17,827 19.7%	$3,499 1.2%	$5,437,120 58.5%
Other	$17 0.0%	-$19,524 -21.6%	$76 0.0%	$1,853 0.0%
Hawaiian Electric Industries, Inc. (Consolidated)	$3,218,920	$90,278	$282,051	$9,295,082

Source: HEI. 2008 Form 10-K.

BOND RATINGS

	HECO		MECO		HELCO		HEI	
Date	Moody's	S&P	Moody's	S&P	Moody's	S&P	Moody's	S&P
Corporate Credit Rating	Baa1	BBB						BBB
First Mortgage Bonds	A3	A-						
Revenue Bonds (uninsured)	Baa1	BBB	Baa1	BBB	Baa1	BBB		
Medium Term Notes	Baa1	BBB+	Baa1	BBB+	Baa1	BBB+	Baa2	BBB

Note: HECO, MECO, and HELCO no longer have any first mortgage bonds, medium term notes, or uninsured revenue bonds outstanding.

Source: Response to CA-IR-11.

HISTORY OF SECURITY RATINGS
HAWAIIAN ELECTRIC COMPANY

	First Mortgage Bonds		Revenue Bonds		Preferred Stock		Commercial Paper	
Year	Moody's	S&P	Moody's	S&P	Moody's	S&P	Moody's	S&P
1974	A	A	A		a	A	P-1	
1975	A	A	A		a	A	P-1	
1976	A	A	A		a	A	P-1	
1977	A	A	A		a	A	P-1	A-1
1978	A	A	A		a	A	P-1	A-1
1979	A	A	A		a	A	P-1	A-1
1980	A	A	A		a	A	P-1	A-1
1981	A	A	A		a	A	P-1	A-1
1982	A1	A+	A2	A	a1	A+	P-1	A-1
1983	A1	A+	A2	A	a1	A+	P-1	A-1
1984	A1	A+	A2	A	a1	A+	P-1	A-1+
1985	A1	A+	A2	A	a1	A+	P-1	A-1+
1986	Aa3	A+	A1	A	aa3	A+	P-1	A-1+
1987	Aa3	A	A1	A-	aa3	A-	P-1	A-1
1988	Aa3	A	A1	A-	aa3	A-	P-1	A-1
1989	A1	A	A2	A-	a1	A-	P-1	A-1
1990	A2	A-	A3	BBB+	a2	BBB+	P-1	A-2
1991	A3	A-	Baa1	BBB+	baa1	BBB+	P-2	A-2
1992	A3	A-	Baa1	BBB+	baa1	BBB+	P-2	A-2
1993	A3	BBB+	Baa1	BBB+	baa1	BBB+	P-2	A-2
1994	A3	BBB+	Baa1	BBB+	baa1	BBB+	P-2	A-2
1995	A3	BBB+	Baa1	BBB+	baa1	BBB+	P-2	A-2
1996	A3	BBB+	Baa1	BBB+	baa1	BBB+	P-2	A-2
1997	A3	A-	Baa1	BBB+	baa1	BBB+	P-2	A-2
1998	A3	A-	Baa1	BBB+	baa1	BBB-	P-2	A-2
1999	All first mortgage bonds		Baa1	BBB+	baa1	BBB-	P-2	A-2
2000	redeemed in 1999.		Baa1	BBB+	baa1	BBB-	P-2	A-2
2001			Baa1	BBB+	baa2	BBB-	P-2	A-2
2002			Baa1	BBB+	baa2	BBB-	P-2	A-2
2003			Baa1	BBB+	baa2	BBB-	P-2	A-2
2004			Baa1	BBB+	baa2	BBB-	P-2	A-2
2005			Baa1	BBB+	baa2	BBB-	P-2	A-2
2006			Baa1	BBB+	baa2	BBB-	P-2	A-2
2007			Baa1	BBB+	baa2	BBB-	P-2	A-2
2008			Baa1	BBB	baa3		P-2	A-2

Sources: Response to CA-IR-11 and responses to data requests in prior proceedings.

HAWAIIAN ELECTRIC COMPANY (OAHU ONLY)
CAPITAL STRUCTURE RATIOS
2003 - 2007
($000)

YEAR	COMMON EQUITY	PREFERRED SECURITIES	LONG-TERM DEBT	SHORT-TERM DEBT
2003	$582,562	$82,293	$434,824	$20,700
	52.0%	7.3%	38.8%	1.8%
	53.0%	7.5%	39.5%	
2004	$640,892	$52,293	$436,403	$61,460
	53.8%	4.4%	36.6%	5.2%
	56.7%	4.6%	38.6%	
2005	$655,544	$52,293	$449,586	$91,715
	52.5%	4.2%	36.0%	7.3%
	56.6%	4.5%	38.8%	
2006	$590,608	$52,293	$449,694	$58,707
	51.3%	4.5%	39.1%	5.1%
	54.1%	4.8%	41.2%	
2007	$699,551	$52,293	$536,111	$30,791
	53.0%	4.0%	40.7%	2.3%
	54.3%	4.1%	41.6%	

Note: Percentages may not total 100.0% due to rounding.

Source: Response to CA-IR-8.

HAWAIIAN ELECTRIC COMPANY (CONSOLIDATED)
CAPITAL STRUCTURE RATIOS
2003 - 2008
($000)

YEAR	COMMON EQUITY	PREFERRED SECURITIES	LONG-TERM DEBT	SHORT-TERM DEBT
2003	$944,443	$134,293	$699,420	$6,000
	52.9%	7.5%	39.2%	0.3%
	53.1%	7.6%	39.3%	
2004	$1,017,104	$34,293	$752,735	$88,568
	53.7%	1.8%	39.8%	4.7%
	56.4%	1.9%	41.7%	
2005	$1,039,259	$24,293	$765,993	$136,165
	52.9%	1.2%	39.0%	6.9%
	56.8%	1.3%	41.9%	
2006	$958,203	$34,293	$766,185	$113,107
	51.2%	1.8%	40.9%	6.0%
	54.5%	1.9%	43.6%	
2007	$1,110,462	$34,293	$833,553	$28,791
	55.3%	1.7%	41.5%	1.4%
	56.1%	1.7%	42.1%	
2008	$1,188,842	$34,293	$904,501	$41,550
	54.8%	1.6%	41.7%	1.9%
	55.9%	1.6%	42.5%	

Note: Percentages may not total 100.0% due to rounding.

Source: Response to CA-IR-8 and HEI 2008 Annual Report.

HAWAIIAN ELECTRIC INDUSTRIES, INC.
CAPITAL STRUCTURE RATIOS
2003 - 2008
($000)

YEAR	COMMON EQUITY	PREFERRED SECURITIES	LONG-TERM DEBT	SHORT-TERM DEBT
2003	$1,089,031	$234,406	$1,064,420	$0
	45.6%	9.8%	44.6%	0.0%
	45.6%	9.8%	44.6%	
2004	$1,210,945	$34,405	$1,166,735	$76,611
	48.7%	1.4%	46.9%	3.1%
	50.2%	1.4%	48.4%	
2005	$1,216,630	$34,293	$1,142,993	$141,758
	48.0%	1.4%	45.1%	5.6%
	50.8%	1.4%	47.7%	
2006	$1,095,240	$34,293	$1,133,185	$176,272
	44.9%	1.4%	46.5%	7.2%
	48.4%	1.5%	50.1%	
2007	$1,275,427	$34,293	$1,242,099	$91,780
	48.2%	1.3%	47.0%	3.5%
	50.0%	1.3%	48.7%	
2008	$1,389,454	$34,293	$1,211,501	$0
	52.7%	1.3%	46.0%	0.0%
	52.7%	1.3%	46.0%	

Note: Percentages may not total 100.0% due to rounding.

Long-term and short-term debt figures do not include borrowings of bank.

Source: Hawaiian Electric Industries, Inc. Form 10-K.

AUS UTILITY REPORTS
ELECTRIC UTILITY GROUPS
AVERAGE COMMON EQUITY RATIOS

Year	Electric	Combination Electric and Gas
2003	42%	38%
2004	47%	43%
2005	44%	47%
2006	45%	44%
2007	47%	46%
2008	45%	43%

Note: Averages include short-term debt.

Source: AUS Utility Reports.

COMPARISON COMPANIES
BASIS FOR SELECTION
USING COMMISSION CRITERIA

Company	Market Cap (000)	Percent Revenues Electric	Common Equity Ratio	Value Line Safety	Moody's/ Bond Rating
Hawaiian Electric Industries	$1,900,000	84%	49%	2	Baa2
Comparison Group*					
Empire District Electric	$575,000	87%	50%	3	Baa1
IDACORP	$1,400,000	100%	51%	3	A3
NV Energy	$3,200,000	94%	42%	3	Baa3
Northeast Utilities	$3,600,000	85%	49%	3	Baa1
NSTAR	$3,600,000	79%	40%	1	A1
Pinnacle West Capital	$3,500,000	77%	52%	1	Baa2
Pepco Holdings, Inc.	$3,400,000	53%	46%	3	Baa1
Portland General	$1,200,000	99%	47%	2	Baa1
SCANA Corp	$3,700,000	42%	50%	2	A2
UIL Holdings	$625,000	100%	49%	2	Baa2
Westar Energy	$2,100,000	69%	49%	2	Baa2

* Selected using following criteria:
Market cap of $500 million to $5 billion.
Electric Revenues of 40% or greater.
Common Equity Ratio of 35% to 55%.
Value Line Safety of 1, 2 or 3.
Moody's bond ratings of Baa or A

Sources: C.A. Turner Utility Reports, Standard & Poor's Stock Guide, Value Line Investment Survey.

COMPARISON COMPANIES
BASIS FOR SELECTION
USING PARCELL CRITERIA

Company	Net Utility Plant (000)	Percent Revenues Electric	Common Equity Ratio	Standard & Poor's Stock Ranking	Moody's/ Bond Rating
Hawaiian Electric Industries	$2,743,400	85%	49%	B	Baa2
Comparison Group*					
Avista	$2,351,300	50%	59%	B	Baa2
Cleco Corp.	$1,725,900	96%	57%	B+	A3
Empire District Electric	$1,178,900	87%	50%	B	Baa1
IDACORP	$2,616,600	100%	51%	B	A3
NSTAR	$4,142,300	79%	40%	A-	A1
Portland General	$3,310,000	99%	47%	NR	Baa1
Westar Energy, Inc.	$4,803,700	69%	49%	B	Baa2

* Selected using following criteria:
Net Utility Plant of $1 billion to $5 billion.
Electric Revenues of 50% or greater.
Common Equity Ratio of 40% to 55%.
Standard & Poor's Stock Ranking of B or B+.or A-
Moody's bond ratings of BBB or A.
No nuclear generation.

Sources: C.A. Turner Utility Reports, Standard & Poor's Stock Guide, Value Line Investment Survey.

COMPARISON COMPANIES
DIVIDEND YIELD

COMPANY	DPS	April - June, 2009 HIGH	LOW	AVERAGE	YIELD
Comparison Group - PUC Criteria					
Empire District Electric	$1.28	$16.52	$14.19	$15.36	8.3%
Hawaiian Electric Industries	$1.24	$19.25	$13.52	$16.39	7.6%
IDACORP	$1.20	$26.00	$22.22	$24.11	5.0%
NV Energy	$0.40	$11.19	$9.26	$10.23	3.9%
Northeast Utilities	$0.95	$22.57	$19.78	$21.18	4.5%
NSTAR	$1.50	$34.68	$28.54	$31.61	4.7%
Pinnacle West Capital	$2.10	$29.96	$25.28	$27.62	7.6%
Pepco Holdings, Inc.	$1.08	$13.67	$11.45	$12.56	8.6%
Portland General	$1.02	$20.26	$16.43	$18.35	5.6%
SCANA Corp	*$1.88*	*$32.70*	*$28.21*	*$30.46*	*6.2%*
UIL Holdings	$1.73	$24.39	$20.56	$22.48	7.7%
Westar Energy	$1.20	$19.32	$16.60	$17.96	6.7%
Average					**6.2%**
Comparison Group - Parcell Criteria					
Avista	$0.84	$17.82	$13.44	$15.63	5.4%
Cleco Corp.	$0.90	$22.81	$19.82	$21.32	4.2%
Empire District Electric	$1.28	$16.52	$14.19	$15.36	8.3%
Hawaiian Electric Industries	$1.24	$19.25	$13.52	$16.39	7.6%
IDACORP	$1.20	$26.00	$22.22	$24.11	5.0%
NSTAR	$1.50	$34.68	$28.54	$31.61	4.7%
Portland General	$1.02	$20.26	$16.43	$18.35	5.6%
Westar Energy, Inc.	$1.20	$19.32	$16.60	$17.96	6.7%
Average					**5.9%**
S&P Integrated Electric Utilities					
ALLETE	$1.76	$29.14	$24.45	$26.80	6.6%
Alliant Energy	$1.50	$2,565.00	$22.08	$1,293.54	0.1%
Ameren Corp.	$1.54	$25.04	$21.75	$23.40	6.6%
American Electric Power	$1.64	$28.95	$24.75	$26.85	6.1%
Cleco	$0.90	$22.81	$19.82	$21.32	4.2%
CMS Energy	$0.50	$12.37	$10.89	$11.63	4.3%
DPL	*$1.14*	*$23.67*	*$21.03*	*$22.35*	*5.1%*
DTE Energy	$2.12	$32.28	$27.32	$29.80	7.1%
Edison International	$1.24	$32.52	$27.50	$30.01	4.1%
Empire District Electric	$1.28	$16.52	$14.19	$15.36	8.3%
Entergy	$3.00	$78.78	$63.39	$71.09	4.2%
FPL Group	$1.89	$59.00	$49.70	$54.35	3.5%
Hawaiian Electric Industries	$1.24	$19.25	$13.52	$16.39	7.6%
IDACORP	$1.20	$26.00	$22.22	$24.11	5.0%
MGE Energy	$1.45	$34.00	$29.42	$31.71	4.6%
Northeast Utilites	$0.95	$22.57	$19.78	$21.18	4.5%
PG&E	$1.68	$39.11	$34.60	$36.86	4.6%
Pinnacle West Capital	$2.10	$29.96	$25.28	$27.62	7.6%
PNM Resources	$0.50	$10.77	$7.68	$9.23	5.4%
Portland General	$1.02	$20.26	$16.43	$18.35	5.6%
Progress Energy	$2.48	$37.90	$33.50	$35.70	6.9%
Southern Company	$1.75	$31.82	$27.19	$29.51	5.9%
TECO Energy	$0.80	$12.41	$10.28	$11.35	7.1%
Unisource Eneregy	$1.16	$28.76	$24.78	$26.77	4.3%
Westar Energy	$1.20	$19.32	$16.60	$17.96	6.7%
Wisconsin Energy	$1.35	$42.23	$39.21	$40.72	3.3%
Xcel Energy Inc.	$0.98	$18.98	$17.25	$18.12	5.4%
Average					**5.3%**
Moody's Electric Utilities					
American Electric Power	$1.64	$28.95	$24.75	$26.85	6.1%
CH Energy	$2.16	$46.84	$40.60	$43.72	4.9%
Consolidated Edison	$2.36	$40.00	$34.36	$37.18	6.3%
Constellation Energy	$0.96	$28.05	$20.18	$24.12	4.0%
Dominion Resources	$1.75	$37.18	$29.26	$33.22	5.3%
DPL Inc	$1.14	$23.67	$21.03	$22.35	5.1%
DTE Energy	$2.12	$32.28	$27.32	$29.80	7.1%
Duke Energy	$0.92	$14.83	$13.31	$14.07	6.5%
Exelon Corp	$2.10	$51.46	$44.24	$47.85	4.4%
Firstenergy	$2.20	$43.29	$35.26	$39.28	5.6%
IDACORP	$1.20	$26.00	$22.22	$24.11	5.0%
NiSource	$0.92	$11.62	$9.64	$10.63	8.7%
OGE Energy	$1.42	$28.30	$23.19	$25.75	5.5%
PPL Corp	$1.38	$34.42	$27.40	$30.91	4.5%
Progress Energy	$2.48	$37.90	$33.50	$35.70	6.9%
Public Service Enterprise	$1.33	$33.94	$27.85	$30.90	4.3%
Southern Co.	$1.75	$31.82	$27.19	$29.51	5.9%
TECO Energy	$0.80	$12.41	$10.28	$11.35	7.1%
Xcel Energy Inc.	$0.98	$18.98	$17.25	$18.12	5.4%
Average					**5.7%**

Source: Yahoo! Finance.

COMPARISON COMPANIES
RETENTION GROWTH RATES

COMPANY	2004	2005	2006	2007	2008	Average	2009	2010	2011-2013	Average
Comparison Group - PUC Criteria										
Empire District Electric	0.0%	0.0%	0.8%	0.0%	0.0%	0.2%	2.0%	2.5%	3.0%	2.5%
Hawaiian Electric Industries	1.1%	1.5%	0.7%	0.8%	0.5%	0.9%	0.5%	2.5%	3.0%	2.0%
IDACORP	2.7%	1.3%	4.3%	2.4%	3.4%	2.8%	3.5%	4.0%	4.0%	3.8%
NV Energy	4.8%	4.0%	9.0%	5.4%	4.1%	5.5%	2.0%	4.0%	3.5%	3.2%
Northeast Utilities	1.6%	1.5%	0.3%	4.3%	5.3%	2.6%	4.5%	4.5%	4.5%	4.5%
NSTAR	4.8%	4.6%	4.9%	4.9%	4.9%	4.8%	5.0%	5.0%	6.0%	5.3%
Pinnacle West Capital	2.3%	1.0%	3.4%	2.5%	0.3%	1.9%	1.0%	2.0%	3.0%	2.0%
Pepco Holdings, Inc.	2.5%	2.4%	1.5%	2.3%	4.2%	2.6%	2.0%	3.0%	3.5%	2.8%
Portland General	7.2%	5.3%	3.5%	6.6%	2.0%	4.9%	4.0%	3.5%	4.0%	3.8%
SCANA Corp	5.6%	5.3%	3.8%	4.0%	4.4%	4.6%	4.0%	3.5%	4.0%	3.8%
UIL Holdings	0.0%	0.0%	0.0%	3.1%	1.0%	0.8%	1.0%	1.5%	2.5%	1.7%
Westar Energy	3.2%	4.3%	5.5%	4.3%	1.2%	3.7%	2.0%	2.5%	3.0%	2.5%
Average						**2.9%**				**3.2%**
Comparison Group - Parcell Criteria										
Avista	1.4%	2.4%	4.9%	0.8%	3.7%	2.6%	4.0%	3.5%	2.5%	3.3%
Cleco Corp.	3.9%	4.1%	3.0%	2.6%	4.5%	3.6%	4.0%	5.0%	4.5%	4.5%
Empire District Electric	0.0%	0.0%	0.8%	0.0%	0.0%	0.2%	2.0%		3.0%	2.5%
Hawaiian Electric Industries	1.1%	1.5%	0.7%	0.8%	0.5%	0.9%	0.5%		3.0%	1.8%
IDACORP	2.7%	1.3%	4.3%	2.4%	3.4%	2.8%	3.5%		4.0%	3.8%
NSTAR	4.8%	4.6%	4.9%	4.9%	4.9%	4.8%	5.0%	5.0%	6.0%	5.3%
Portland General	7.2%	5.3%	3.5%	6.6%	2.0%	4.9%	4.0%		4.0%	4.0%
Westar Energy, Inc.	3.2%	4.3%	5.5%	4.3%	1.2%	3.7%	2.0%		3.0%	2.5%
Average						**3.0%**				**3.5%**

S&P Integrated
Electric Utilities

COMPARISON COMPANIES
PER SHARE GROWTH RATES

COMPANY	5-Year Historic Growth Rates EPS	DPS	BVPS	Average	Est'd '05-'07 to '11-'13 Growth Rates EPS	DPS	BVPS	Average
Comparison Group - PUC Criteria								
Empire District Electric	3.5%		1.5%	2.5%	8.5%	1.5%	2.0%	4.0%
Hawaiian Electric Industries	-6.0%	0.0%	1.0%	-1.7%	7.0%	0.0%	2.5%	3.2%
IDACORP	1.5%	-8.0%	3.0%	-1.2%	4.5%	0.0%	5.0%	3.2%
NV Energy		-3.5%	-2.0%	-2.8%	4.5%		3.5%	4.0%
Northeast Utilities	3.0%	8.5%	2.0%	4.5%	8.0%	6.5%	5.0%	6.5%
NSTAR	4.0%	6.0%	5.0%	5.0%	8.0%	5.5%	5.5%	6.3%
Pinnacle West Capital	-1.0%	5.0%	3.0%	2.3%	3.0%	1.0%	1.0%	1.7%
Pepco Holdings, Inc.	-2.0%	17.5%	1.5%	5.7%	3.0%		2.5%	2.8%
Portland General					5.5%	7.0%	3.0%	5.2%
SCANA Corp	3.5%	6.5%	4.0%	4.7%	4.0%	3.0%	4.5%	3.8%
UIL Holdings			-2.0%	-2.0%	2.5%	0.0%	1.5%	1.3%
Westar Energy	21.5%	-0.5%	1.0%	7.3%	4.0%	4.5%	6.0%	4.8%
Average				**2.2%**				**3.9%**
Comparison Group - Parcell Criteria								
Avista	4.0%	5.0%	3.0%	4.0%	6.5%	12.5%	3.5%	7.5%
Cleco Corp.	0.5%	0.5%	9.0%	3.3%	9.5%	10.0%	5.5%	8.3%
Empire District Electric	3.5%		1.5%	2.5%	8.5%	1.5%	2.0%	4.0%
Hawaiian Electric Industries	-6.0%	0.0%	1.0%	-1.7%	7.0%	0.0%	2.5%	3.2%
IDACORP	1.5%	-8.0%	3.0%	-1.2%	4.5%	0.0%	5.0%	3.2%
NSTAR	4.0%	6.0%	5.0%	5.0%	8.0%	5.5%	5.5%	6.3%
Portland General					5.5%	7.0%	3.0%	5.2%
Westar Energy, Inc.	21.5%	-0.5%	1.0%	7.3%	4.0%	4.5%	6.0%	4.8%
Average				**2.8%**				**5.3%**
S&P Integrated Electric Utilities								
ALLETE					-1.0%	3.0%	3.5%	1.8%
Alliant Energy	7.0%	-5.0%	3.0%	1.7%	4.5%	7.0%	4.0%	5.2%
Ameren Corp.	-1.5%	0.0%	5.0%	1.2%	2.5%	-6.5%	3.5%	-0.2%
American Electric Power		-6.0%	2.5%	-1.8%	3.0%	3.0%	5.0%	3.7%
Cleco	0.5%	0.5%	9.0%	3.3%	9.5%	10.0%	5.5%	8.3%
CMS Energy		-26.0%	-1.0%	-13.5%	10.0%	27.5%	6.0%	14.5%
DPL	7.0%	2.0%	2.5%	3.8%	8.0%	3.5%	11.0%	7.5%
DTE Energy	-2.0%	0.5%	4.0%	0.8%	7.5%	3.0%	2.5%	4.3%
Edison International	13.5%		14.5%	14.0%	3.5%	4.5%	7.0%	5.0%
Empire District Electric	3.5%		1.5%	2.5%	8.5%	1.5%	2.0%	4.0%
Entergy	10.5%	13.0%	3.0%	8.8%	6.0%	6.5%	6.5%	6.3%
FPL Group	9.5%	7.0%	8.0%	8.2%	10.0%	6.0%	8.5%	8.2%
Hawaiian Electric Industnes	-6.0%	0.0%	1.0%	-1.7%	7.0%	0.0%	2.5%	3.2%
IDACORP	1.5%	-8.0%	3.0%	-1.2%	4.5%	0.0%	5.0%	3.2%
MGE Energy	6.0%	1.0%	8.0%	5.0%	6.0%	0.5%	7.0%	4.5%
Northeast Utilities	3.0%	8.5%	2.0%	4.5%	8.0%	6.5%	5.0%	6.5%
PG&E	26.5%		18.0%	22.3%	6.5%	7.5%	6.5%	6.8%
Pinnacle West Capital	-1.0%	5.0%	3.0%	2.3%	3.0%	1.0%	1.0%	1.7%
PNM Resources	-11.5%	6.5%	4.0%	-0.3%	5.0%			5.0%
Portland General					5.5%	7.0%	3.0%	5.2%
Progress Energy	-6.5%	2.0%	2.5%	-0.7%	6.0%	1.0%	2.0%	3.0%
Southern Company	4.0%	3.0%	5.5%	4.2%	4.5%	4.0%	5.5%	4.7%
TECO Energy	-5.0%	-9.0%	-6.5%	-6.8%	4.5%	2.5%	4.5%	3.8%
Unisource Eneregy	-1.5%	12.5%	6.5%	5.8%	17.5%	10.0%	7.5%	11.7%
Westar Energy	21.5%	-0.5%	1.0%	7.3%	4.0%	4.5%	6.0%	4.8%
Wisconsin Energy	6.0%	4.5%	7.5%	6.0%	8.0%	13.5%	6.0%	9.2%
Xcel Energy Inc.	1.0%	-4.0%	1.0%	-0.7%	6.5%	3.0%	4.5%	4.7%
Average				**3.0%**				**5.4%**
Moody's Electric Utilities								
American Electric Power		-6.0%	2.5%	-1.8%	3.0%	3.0%	5.0%	3.7%
CH Energy	-1.5%	0.0%	1.5%	0.0%	3.0%	0.0%	2.0%	1.7%
Consolidated Edison	1.5%	1.0%	3.5%	2.0%	2.5%	1.0%	4.0%	2.5%
Constellation Energy	11.0%	8.0%	4.0%	7.7%	-2.0%	-3.5%	-1.5%	-2.3%
Dominion Resources	5.5%	2.5%	1.5%	3.2%	8.0%	7.0%	7.5%	7.5%
DPL Inc	7.0%	2.0%	2.5%	3.8%	8.0%	3.5%	11.0%	7.5%
DTE Energy	-2.0%	0.5%	4.0%	0.8%	7.5%	3.0%	2.5%	4.3%
Duke Energy					5.0%		-0.5%	2.3%
Exelon Corp	10.5%	15.0%	4.5%	10.0%	7.5%	5.5%	9.0%	7.3%
Firstenergy	12.5%	6.5%	3.0%	7.3%	4.0%	4.5%	4.5%	4.3%
IDACORP	1.5%	-8.0%	3.0%	-1.2%	4.5%	0.0%	5.0%	3.2%
NiSource	-5.0%	-4.0%	1.5%	-2.5%	1.0%	0.0%	0.5%	0.5%
OGE Energy	11.0%	0.5%	7.0%	6.2%	4.5%	3.0%	7.0%	4.8%
PPL Corp	7.5%	12.5%	13.5%	11.2%	10.5%	12.0%	7.5%	10.0%
Progress Energy	-6.5%	2.0%	2.5%	-0.7%	6.0%	1.0%	2.0%	3.0%
Public Service Enterprise	5.5%	2.0%	7.0%	4.8%	7.5%	6.0%	9.5%	7.7%
Southern Co.	4.0%	3.0%	5.5%	4.2%	4.5%	4.0%	5.5%	4.7%
TECO Energy	-5.0%	-9.0%	-6.5%	-6.8%	4.5%	2.5%	4.5%	3.8%
Xcel Energy Inc.	1.0%	-4.0%	1.0%	-0.7%	6.5%	3.0%	4.5%	4.7%
Average				**2.6%**				**4.3%**

Source: Value Line Investment Survey.

CA-S-408
Docket No. 2008-0083
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Updated

COMPARISON COMPANIES
DCF COST RATES

COMPANY	ADJUSTED YIELD	HISTORIC RETENTION GROWTH	PROSPECTIVE RETENTION GROWTH	HISTORIC PER SHARE GROWTH	PROSPECTIVE PER SHARE GROWTH	FIRST CALL EPS GROWTH	AVERAGE GROWTH	DCF RATES
Comparison Group - PUC Criteria								
Empire District Electric	8.5%	0.2%	2.5%	2.8%	4.0%	6.0%	3.0%	11.5%
Hawaiian Electric Industries	7.7%	0.9%	2.0%		3.2%	5.0%	3.0%	10.7%
IDACORP	5.1%	2.8%	3.8%		3.2%	5.0%	3.7%	8.8%
NV Energy	4.0%	5.5%	3.2%		4.0%	13.3%	6.5%	10.5%
Northeast Utilities	4.6%	2.8%	4.5%	4.5%	6.5%	7.5%	5.1%	9.7%
NSTAR	4.8%	4.8%	5.3%	5.8%	6.3%	6.7%	5.8%	10.9%
Pinnacle West Capital	7.7%	1.9%	2.0%	2.3%	1.7%	4.9%	2.5%	10.2%
Pepco Holdings, Inc.	8.7%	2.6%	2.6%	5.7%	2.6%	3.7%	3.5%	12.2%
Portland General	5.7%	4.9%	3.6%	0.0%	5.2%	7.1%	4.2%	9.9%
SCANA Corp	6.3%	4.6%	3.8%	4.7%	3.8%	5.4%	4.3%	10.8%
UIL Holdings	7.8%	0.8%	1.7%		1.3%	4.9%	2.1%	9.8%
Westar Energy	6.8%	3.7%	2.5%	7.3%	4.8%	3.9%	4.4%	11.2%
Mean	6.5%	2.9%	3.2%	4.0%	3.9%	6.1%	4.0%	10.5%
Median	6.6%	2.7%	3.0%	4.6%	3.8%	5.8%	4.0%	10.5%
Mean Composite		9.4%	9.6%	10.5%	10.4%	12.6%	10.9%	
Median Composite		9.3%	9.6%	11.2%	10.6%	12.2%	10.9%	
Comparison Group - Parcell Criteria								
Avista	5.8%	2.6%	3.3%	4.0%	7.9%	5.0%	4.5%	10.0%
Cleco Corp	4.4%	3.6%	4.6%	3.3%	8.3%	11.7%	6.3%	10.7%
Empire District Electric	8.5%	0.2%	2.5%	2.5%	4.0%	6.0%	3.0%	11.5%
Hawaiian Electric Industries	7.7%	0.9%	1.9%		3.2%	5.0%	2.8%	10.6%
IDACORP	5.1%	2.8%	3.8%		3.2%	5.0%	3.7%	8.8%
NSTAR	4.8%	4.8%	5.3%	5.0%	6.3%	6.7%	5.8%	10.9%
Portland General	5.7%	4.9%	4.0%		5.2%	7.1%	5.3%	11.0%
Westar Energy, Inc.	6.8%	3.7%	2.5%	7.3%	4.8%	3.9%	4.4%	11.2%
Mean	6.1%	3.0%	3.6%	4.4%	5.3%	6.3%	4.9%	10.8%
Median	5.8%	3.2%	3.5%	4.0%	5.0%	5.8%	4.4%	10.8%
Mean Composite		9.8%	9.5%	10.8%	11.4%	12.4%	10.6%	
Median Composite		8.8%	9.1%	9.8%	10.6%	11.8%	10.8%	
S&P Integrated Electric Utilities								
ALLETE	6.7%	4.8%	1.5%		1.8%	6.0%	3.6%	10.3%
Alliant Energy	0.1%	5.1%	2.8%	1.7%	5.2%	6.0%	4.1%	4.3%
Ameren Corp.	6.7%	1.0%	3.8%	1.2%		4.0%	2.5%	9.2%
American Electric Power	6.2%	5.4%	4.7%		3.7%	3.4%	4.3%	10.5%
Cleco	4.4%	3.6%	4.9%	8.3%	8.3%	14.3%	6.6%	11.1%
CMS Energy	4.5%	7.2%	6.3%		14.8%	6.7%	8.7%	13.2%
DPL	5.3%	7.3%	10.5%	3.8%	7.9%	7.4%	7.3%	12.6%
DTE Energy	7.2%	1.9%	3.0%	0.8%	4.3%	3.5%	2.7%	9.8%
Edison International	4.3%	6.6%	6.2%	14.8%	5.0%	1.3%	6.9%	11.2%
Empire District Electric	8.5%	0.2%	2.5%	2.8%	4.0%	6.0%	3.0%	12.1%
Entergy	4.4%	7.2%	6.9%	6.8%	6.3%	8.4%	8.1%	12.6%
FPL Group	3.6%	6.1%	8.6%	6.2%	8.2%	9.6%	8.8%	11.7%
Hawaiian Electric Industries	7.7%	0.9%	1.6%		3.2%	5.6%	3.8%	10.6%
IDACORP	5.1%	2.8%	3.8%		3.2%	5.0%	3.7%	8.8%
MGE Energy	4.7%	3.2%	5.8%	5.0%	4.3%		4.4%	9.1%
Northeast Utilities	4.6%	2.8%	4.3%	4.5%	6.5%	7.5%	5.1%	9.7%
PG&E	4.8%	7.5%	5.7%	22.3%	6.8%	6.7%	9.9%	14.8%
Pinnacle West Capital	7.7%	1.9%	2.0%	2.3%	1.7%	7.1%	3.0%	10.7%
PNM Resources	5.5%	2.8%	1.5%		5.0%	5.0%	3.5%	9.0%
Portland General	5.7%	4.9%	4.0%		5.3%	7.1%	5.3%	11.0%
Progress Energy	7.1%	1.3%	2.5%		3.0%	5.6%	3.1%	10.3%
Southern Company	6.1%	4.2%	4.0%	4.2%	4.7%	5.4%	4.5%	10.6%
TECO Energy	7.2%	2.7%	3.7%		3.6%	8.5%	4.7%	11.9%
Unisource Energy	4.5%	3.5%	5.8%	6.9%	11.7%	5.0%	6.4%	10.9%
Westar Energy	6.8%	3.7%	2.5%	7.3%	4.8%	3.9%	4.4%	11.2%
Wisconsin Energy	3.4%	6.7%	6.6%	6.0%	9.2%	9.0%	7.5%	10.9%
Xcel Energy Inc.	5.5%	3.5%	4.0%		4.7%	6.4%	4.6%	10.2%
Mean	5.5%	4.1%	4.4%	6.0%	5.6%	6.5%	5.2%	10.7%
Median	5.5%	3.0%	4.0%	4.5%	4.8%	6.2%	4.5%	10.7%
Composite-Mean		9.8%	9.9%	11.5%	11.1%	12.8%	10.7%	
Composite-Median		9.1%	9.5%	10.0%	10.4%	11.7%	10.0%	
Moody's Electric Utilities								
American Electric Power	6.2%	5.4%	4.8%		3.7%	3.4%	4.3%	10.5%
CH Energy	5.0%	1.4%	1.5%	0.0%	1.7%		1.1%	6.1%
Consolidated Edison	6.4%	2.8%	2.5%	2.0%	2.5%	2.1%	2.3%	8.8%
Constellation Energy	4.2%	6.7%	6.4%	7.7%		14.8%	8.9%	13.1%
Dominion Resources	5.4%	5.0%	7.2%	3.2%	7.5%	6.2%	6.2%	11.6%
DPL Inc	5.3%	7.3%	10.3%	3.8%	7.5%	7.4%	7.3%	12.5%
DTE Energy	7.2%	1.9%	3.0%	0.8%	4.3%	3.5%	2.7%	9.8%
Duke Energy	6.6%	2.2%	1.2%	0.0%	2.3%	3.6%	1.9%	8.6%
Exelon Corp	4.6%	12.7%	11.9%	10.6%	7.3%	5.2%	8.3%	13.0%
FirstEnergy	5.0%	6.5%	5.7%	7.3%	4.3%	6.7%	6.1%	11.0%
IDACORP	5.1%	2.8%	3.8%		3.2%	5.0%	3.7%	8.8%
NiSource	8.7%	1.0%	1.5%		0.8%	1.8%	1.4%	10.1%
OGE Energy	5.7%	5.2%	5.3%	6.2%	4.8%	6.0%	5.5%	11.2%
PPL Corp	4.7%	9.2%	8.7%	11.2%	18.0%	12.7%	10.3%	15.0%
Progress Energy	7.1%	1.3%	2.3%		3.0%	5.6%	3.1%	10.1%
Public Service Enterprise	4.5%	6.8%	9.8%	4.8%	7.7%	7.0%	7.2%	11.7%
Southern Co.	6.1%	4.2%	4.0%	4.2%	4.7%	6.4%	4.5%	10.5%
TECO Energy	7.2%	2.7%	3.7%		3.6%	8.5%	4.7%	11.9%
Xcel Energy Inc.	5.5%	3.5%	4.3%		4.7%	6.4%	4.7%	10.2%
Mean	5.9%	4.7%	5.1%	4.7%	4.6%	6.9%	5.8%	10.9%
Median	5.7%	4.2%	4.3%	4.2%	4.3%	5.6%	4.7%	10.5%
Composite-Mean		10.5%	11.0%	10.6%	10.9%	12.1%	10.6%	
Composite-Median		9.8%	9.8%	9.8%	10.0%	11.5%	10.3%	

Sources: Prior pages of this schedule.
Note: Negative average values not considered

Sources: Prior pages of this schedule

COMPARISON COMPANIES
DIVIDEND YIELD

COMPANY	DPS	July 6, 2009 Price	YIELD
Comparison Group - PUC Criteria			
Empire District Electric	$1.28	$16.79	7.6%
Hawaiian Electric Industries	$1.24	$19.03	6.5%
IDACORP	$1.20	$25.73	4.7%
NV Energy	$0.40	$10.89	3.7%
Northeast Utilities	$0.95	$22.51	4.2%
NSTAR	$1.50	$31.74	4.7%
Pinnacle West Capital	$2.10	$30.16	7.0%
Pepco Holdings, Inc.	$1.08	$13.22	8.2%
Portland General	$1.02	$19.24	5.3%
SCANA Corp	$1.88	$32.39	5.8%
UIL Holdings	$1.73	$22.67	7.6%
Westar Energy	$1.20	$18.65	6.4%
Average			5.8%
Comparison Group - Parcell Criteria			
Avista	$0.84	$17.92	4.7%
Cleco Corp.	$0.90	$22.34	4.0%
Empire District Electric	$1.28	$16.79	7.6%
Hawaiian Electric Industries	$1.24	$19.03	6.5%
IDACORP	$1.20	$25.73	4.7%
NSTAR	$1.50	$31.74	4.7%
Portland General	$1.02	$19.24	5.3%
Westar Energy, Inc.	$1.20	$18.65	6.4%
Average			5.5%
S&P Integrated Electric Utilities			
ALLETE	$1.76	$28.46	6.2%
Alliant Energy	$1.50	$26.34	5.7%
Ameren Corp.	$1.54	$24.27	6.3%
American Electric Power	$1.64	$28.82	5.7%
Cleco	$0.90	$22.34	4.0%
CMS Energy	$0.50	$12.16	4.1%
DPL	$1.14	$23.44	4.9%
DTE Energy	$2.12	$32.04	6.6%
Edison International	$1.24	$31.27	4.0%
Empire District Electric	$1.28	$16.79	7.6%
Entergy	$3.00	$75.36	4.0%
FPL Group	$1.89	$55.28	3.4%
Hawaiian Electric Industries	$1.24	$19.03	6.5%
IDACORP	$1.20	$25.73	4.7%
MGE Energy	$1.45	$33.97	4.3%
Northeast Utilities	$0.95	$22.51	4.2%
PG&E	$1.68	$38.30	4.4%
Pinnacle West Capital	$2.10	$30.16	7.0%
PNM Resources	$0.50	$10.68	4.7%
Portland General	$1.02	$19.24	5.3%
Progress Energy	$2.48	$37.93	6.5%
Southern Company	$1.75	$31.67	5.5%
TECO Energy	$0.80	$11.62	6.9%
Unisource Energy	$1.16	$26.45	4.4%
Westar Energy	$1.20	$18.65	6.4%
Wisconsin Energy	$1.35	$41.19	3.3%
Xcel Energy Inc.	$0.98	$18.45	5.3%
Average			5.2%
Moody's Electric Utilities			
American Electric Power	$1.64	$28.82	5.7%
CH Energy	$2.16	$47.66	4.5%
Consolidated Edison	$2.36	$37.47	6.3%
Constellation Energy	$0.96	$25.98	3.7%
Dominion Resources	$1.75	$33.01	5.3%
DPL Inc	$1.14	$23.07	4.9%
DTE Energy	$2.12	$31.62	6.7%
Duke Energy	$0.92	$14.55	6.3%
Exelon Corp	$2.10	$48.65	4.3%
Firstenergy	$2.20	$42.13	5.2%
IDACORP	$1.20	$25.73	4.7%
NiSource	$0.92	$11.93	7.7%
OGE Energy	$1.42	$28.16	5.0%
PPL Corp	$1.38	$32.18	4.3%
Progress Energy	$2.48	$37.93	6.5%
Public Service Enterprise	$1.33	$32.00	4.2%
Southern Co.	$1.75	$31.67	5.5%
TECO Energy	$0.80	$11.62	6.9%
Xcel Energy Inc.	$0.98	$18.45	5.3%
Average			5.4%

Source: Yahoo! Finance.

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Modified

COMPARISON COMPANIES
DCF COST RATES

COMPANY	ADJUSTED YIELD	HISTORIC RETENTION GROWTH	PROSPECTIVE RETENTION GROWTH	HISTORIC PER SHARE GROWTH	PROSPECTIVE PER SHARE GROWTH	FIRST CALL EPS GROWTH	AVERAGE GROWTH	DCF RATES
Comparison Group - PUC Criteria								
Empire District Electric	7.7%	6.2%	2.9%	2.5%	4.0%	6.0%	3.9%	10.8%
Hawaiian Electric Industries	6.0%	0.9%	2.9%		3.2%	5.8%	3.0%	9.0%
IDACORP	4.9%	2.9%	3.9%		3.2%	5.0%	3.7%	8.5%
NV Energy	3.0%	5.9%	3.2%		4.0%	13.3%	6.5%	10.3%
Northeast Utilities	4.3%	2.9%	4.5%	4.5%	6.5%	7.5%	5.1%	9.5%
NSTAR	4.9%	4.9%	5.3%	5.0%	6.3%	6.7%	5.6%	10.5%
Pinnacle West Capital	7.0%	1.9%	2.0%	2.3%	1.7%	4.5%	2.5%	9.5%
Pepco Holdings, Inc	8.3%	2.9%	2.8%	5.7%	2.8%	3.7%	3.5%	11.8%
Portland General	5.4%	4.8%	3.4%	0.0%	5.2%	7.1%	4.2%	9.8%
SCANA Corp	5.9%	4.9%	3.6%	4.7%	3.8%	5.4%	4.5%	10.4%
UIL Holdings	7.7%	8.6%	1.7%		1.3%	4.5%	· 2.1%	9.8%
Westar Energy	6.8%	3.7%	2.5%	7.9%	4.9%	3.5%	4.4%	10.8%
Mean	6.1%	2.9%	3.2%	4.0%	3.9%	6.1%	4.0%	10.1%
Median	6.3%	2.7%	3.0%	4.6%	3.9%	5.8%	4.0%	10.8%
Mean Composite		8.9%	9.3%	10.1%	10.0%	12.2%	10.1%	
Median Composite		9.0%	9.3%	10.8%	10.2%	11.8%	10.2%	
Comparison Group - Parcell Criteria								
Avista	4.8%	2.6%	3.3%	4.0%	7.5%	5.0%	4.6%	9.3%
Cleco Corp	4.3%	3.6%	4.5%	3.3%	6.3%	11.7%	6.3%	10.5%
Empire District Electric	7.7%	8.2%	2.8%	2.5%	4.0%	6.0%	3.0%	10.6%
Hawaiian Electric Industries	6.6%	0.9%	1.9%		3.2%	5.8%	2.9%	9.5%
IDACORP	4.7%	2.8%	3.8%		3.2%	5.0%	3.7%	8.4%
NSTAR	4.9%	4.8%	5.3%	5.0%	6.3%	6.7%	5.8%	10.6%
Portland General	5.4%	4.9%	4.0%		5.2%	7.1%	5.3%	10.7%
Westar Energy, Inc.	6.6%	3.7%	2.5%	7.3%	4.8%	3.8%	4.4%	10.9%
Mean	5.6%	3.0%	3.5%	4.4%	5.3%	6.3%	4.5%	10.1%
Median	5.2%	3.2%	3.5%	4.0%	5.0%	5.9%	4.4%	10.6%
Mean Composite		8.6%	9.1%	10.8%	10.9%	12.0%	10.1%	
Median Composite		8.4%	8.7%	9.2%	10.2%	11.1%	9.9%	
S&P Integrated Electric Utilities								
ALLETE	6.9%	4.6%	1.5%		1.8%	6.0%	3.6%	9.9%
Alliant Energy	5.9%	5.1%	2.8%	1.7%	5.2%	6.0%	4.1%	10.0%
Ameren Corp	6.4%	1.0%	3.8%	1.2%		4.0%	2.5%	8.9%
American Electric Power	5.8%	5.4%	4.7%		3.7%	3.4%	4.3%	10.1%
Cleco	4.2%	3.6%	4.3%	3.3%	6.3%	14.3%	6.4%	10.9%
CMS Energy	4.3%	7.2%	6.3%		14.5%	6.7%	8.7%	13.0%
DPL	5.0%	7.3%	10.5%	3.8%	7.5%	7.4%	7.3%	12.9%
DTE Energy	6.7%	1.9%	3.0%	0.8%	4.3%	3.6%	2.7%	9.4%
Edison International	4.1%	8.0%	6.2%	14.0%	5.0%	1.3%	6.9%	11.0%
Empire District Electric	7.6%	0.2%	2.5%	2.5%	4.0%	8.0%	3.8%	11.4%
Entergy	4.1%	7.2%	8.5%	6.8%	6.5%	9.4%	8.1%	12.2%
FPL Group	3.6%	6.1%	8.0%	8.2%	8.2%	9.8%	8.0%	11.6%
Hawaiian Electric Industries	6.6%	0.9%	1.8%		3.2%	5.8%	2.9%	9.5%
IDACORP	4.7%	2.8%	3.8%		3.2%	5.0%	3.7%	8.4%
MGE Energy	4.4%	3.2%	5.0%	5.0%	4.5%		4.4%	8.8%
Northeast Utilities	4.3%	2.8%	4.5%	4.5%	6.5%	7.5%	5.1%	9.5%
PG&E	4.8%	7.5%	5.7%	22.9%	6.9%	6.7%	9.8%	14.4%
Pinnacle West Capital	7.1%	1.9%	2.0%	2.3%	1.7%	7.1%	3.0%	10.1%
PNM Resources	4.8%	2.8%	1.5%		5.0%	5.0%	3.5%	8.3%
Portland General	5.4%	4.8%	4.0%		5.2%	7.1%	5.3%	10.7%
Progress Energy	6.8%	1.3%	2.5%		3.0%	5.8%	3.1%	9.7%
Southern Company	5.7%	4.2%	4.0%	4.2%	4.7%	5.4%	4.5%	10.1%
TECO Energy	7.0%	2.7%	3.7%		3.8%	6.9%	4.7%	11.7%
Unisource Energy	4.5%	3.8%	5.8%	5.9%	11.7%	6.0%	6.4%	10.9%
Westar Energy	6.6%	3.7%	2.9%	7.9%	4.8%	3.5%	4.4%	10.9%
Wisconsin Energy	3.4%	6.7%	6.9%	6.8%	8.2%	9.0%	7.5%	10.9%
Xcel Energy Inc.	5.4%	3.3%	4.0%		4.7%	5.4%	4.6%	10.1%
Mean	5.4%	4.1%	4.4%	6.8%	5.6%	6.6%	5.2%	10.6%
Median	5.4%	3.8%	4.0%	4.5%	4.8%	6.2%	4.5%	10.1%
Composite-Mean		9.4%	9.8%	11.4%	11.0%	11.9%	10.5%	
Composite-Median		9.1%	9.4%	9.9%	10.4%	11.8%	9.8%	
Moody's Electric Utilities								
American Electric Power	5.8%	5.4%	4.8%		3.7%	3.4%	4.3%	10.1%
CH Energy	4.6%	1.4%	1.5%	0.0%	1.7%		1.1%	5.7%
Consolidated Edison	6.4%	2.6%	2.5%	2.0%	2.5%	2.1%	2.3%	8.7%
Constellation Energy	3.8%	6.7%	6.4%	7.7%		14.8%	8.9%	12.8%
Dominion Resources	5.5%	5.8%	7.2%	3.2%	7.5%	8.2%	6.2%	11.7%
DPL Inc	5.1%	7.3%	10.3%	3.8%	7.5%	7.4%	7.2%	12.4%
DTE Energy	6.8%	1.9%	3.0%	0.8%	4.3%	3.5%	2.7%	9.8%
Duke Energy	6.4%	2.2%	1.2%	0.0%	2.3%	3.9%	1.9%	8.3%
Exelon Corp	4.3%	12.7%	11.3%	10.8%	7.3%	5.2%	9.3%	13.9%
Firstenergy	5.4%	8.5%	5.7%	7.3%	4.3%	6.7%	6.1%	11.8%
IDACORP	4.7%	2.8%	3.8%		3.2%	5.0%	3.7%	8.4%
NiSource	7.8%	1.0%	1.5%		0.5%	1.6%	1.4%	9.2%
OGE Energy	5.2%	5.2%	5.3%	6.2%	4.8%	6.0%	5.5%	10.7%
PPL Corp	4.5%	9.2%	8.7%	11.2%	10.0%	12.7%	10.3%	14.8%
Progress Energy	6.0%	1.3%	2.3%		3.8%	5.8%	3.1%	9.7%
Public Service Enterprise	4.3%	6.9%	9.8%	4.8%	7.7%	7.8%	7.2%	11.8%
Southern Co	5.7%	4.2%	4.8%	4.2%	4.7%	5.4%	4.5%	10.1%
TECO Energy	7.0%	2.7%	3.7%		3.8%	6.5%	4.7%	11.7%
Xcel Energy Inc.	5.4%	3.5%	4.3%		4.7%	6.4%	4.7%	10.1%
Mean	5.6%	4.7%	5.1%	4.7%	4.8%	6.3%	5.0%	10.6%
Median	5.4%	4.3%	4.3%	4.2%	4.3%	5.8%	4.7%	10.1%
Composite-Mean		10.0%	10.7%	10.3%	10.2%	11.8%	10.6%	
Composite-Median		9.8%	9.7%	9.6%	9.8%	11.2%	10.1%	

Sources: Prior pages of this schedule.
Note: Negative average values not considered

Sources: Prior pages of this schedule.

STANDARD & POOR'S 500 COMPOSITE
20-YEAR U.S. TREASURY BOND YIELDS
RISK PREMIUMS

Year	EPS	BVPS	ROE	20-YEAR T-BOND	RISK PREMIUM
1977		$79.07			
1978	$12.33	$85.35	15.00%	7.90%	7.10%
1979	$14.86	$94.27	16.55%	8.86%	7.69%
1980	$14.82	$102.48	15.06%	9.97%	5.09%
1981	$15.36	$109.43	14.50%	11.55%	2.95%
1982	$12.64	$112.46	11.39%	13.50%	-2.11%
1983	$14.03	$116.93	12.23%	10.38%	1.85%
1984	$16.64	$122.47	13.90%	11.74%	2.16%
1985	$14.61	$125.20	11.80%	11.25%	0.55%
1986	$14.48	$126.82	11.49%	8.98%	2.51%
1987	$17.50	$134.07	13.42%	7.92%	5.50%
1988	$23.75	$141.32	17.25%	8.97%	8.28%
1989	$22.87	$147.26	15.85%	8.81%	7.04%
1990	$21.73	$153.01	14.47%	8.19%	6.28%
1991	$16.29	$158.85	10.45%	8.22%	2.23%
1992	$18.86	$149.74	12.22%	7.26%	4.96%
1993	$21.89	$180.88	13.24%	7.17%	6.07%
1994	$30.60	$193.06	16.37%	6.59%	9.78%
1995	$33.96	$216.51	16.58%	7.60%	8.98%
1996	$38.73	$237.08	17.08%	6.18%	10.90%
1997	$39.72	$249.52	16.33%	6.64%	9.69%
1998	$37.71	$266.40	14.62%	5.83%	8.79%
1999	$48.17	$290.68	17.29%	5.57%	11.72%
2000	$50.00	$325.80	16.22%	6.50%	9.72%
2001	$24.70	$337.37	7.45%	5.53%	1.92%
2002	$27.59	$321.72	8.37%	5.59%	2.78%
2003	$48.73	$367.17	14.15%	4.80%	9.35%
2004	$58.55	$414.75	14.98%	5.02%	9.96%
2005	$69.93	$453.06	16.12%	4.69%	11.43%
2006	$81.51	$504.39	17.03%	4.68%	12.35%
2007	$66.17	$529.59	12.80%	4.86%	7.94%
Average					**6.45%**

Sources: Standard & Poor's Analysts' Handbook and Ibbotson Associates 2008 Yearbook.

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COMPARISON COMPANIES
CAPM COST RATES

COMPANY	RISK-FREE RATE	BETA	MARKET PREMIUM	CAPM RATES
Comparison Group - PUC Criteria				
Empire District Electric	4.19%	0.75	5.32%	8.2%
Hawaiian Electric Industries	4.19%	0.60	5.32%	7.4%
IDACORP	4.19%	0.70	5.32%	7.9%
NV Energy	4.19%	0.90	5.32%	9.0%
Northeast Utilities	4.19%	0.70	5.32%	7.9%
NSTAR	4.19%	0.65	5.32%	7.6%
Pinnacle West Capital	4.19%	0.70	5.32%	7.9%
Pepco Holdings, Inc.	4.19%	0.80	5.32%	8.4%
Portland General	4.19%	0.70	5.32%	7.9%
SCANA Corp	4.19%	0.70	5.32%	7.9%
UIL Holdings	4.19%	0.70	5.32%	7.9%
Westar Energy	4.19%	0.75	5.32%	8.2%
Average				8.0%
Median				7.9%
Comparison Group - Parcell Criteria				
Avista	4.19%	0.70	5.32%	7.9%
Cleco Corp.	4.19%	0.70	5.32%	7.9%
Empire District Electric	4.19%	0.75	5.32%	8.2%
Hawaiian Electric Industries	4.19%	0.60	5.32%	7.4%
IDACORP	4.19%	0.70	5.32%	7.9%
NSTAR	4.19%	0.65	5.32%	7.6%
Portland General	4.19%	0.70	5.32%	7.9%
Westar Energy, Inc.	4.19%	0.75	5.32%	8.2%
Mean				7.9%
Median				7.9%
S&P Integrated Electric Utilities				
ALLETE	4.19%	0.70	5.32%	7.9%
Alliant Energy	4.19%	0.70	5.32%	7.9%
Ameren Corp.	4.19%	0.80	5.32%	8.4%
American Electric Power	4.19%	0.75	5.32%	8.2%
Cleco	4.19%	0.70	5.32%	7.9%
CMS Energy	4.19%	0.80	5.32%	8.4%
DPL	4.19%	0.60	5.32%	7.4%
DTE Energy	4.19%	0.75	5.32%	8.2%
Edison International	4.19%	0.80	5.32%	8.4%
Empire District Electric	4.19%	0.75	5.32%	8.2%
Entergy	4.19%	0.70	5.32%	7.9%
FPL Group	4.19%	0.75	5.32%	8.2%
Hawaiian Electric Industries	4.19%	0.60	5.32%	7.4%
IDACORP	4.19%	0.70	5.32%	7.9%
MGE Energy	4.19%	0.65	5.32%	7.6%
Northeast Utilities	4.19%	0.70	5.32%	7.9%
PG&E	4.19%	0.60	5.32%	7.4%
Pinnacle West Capital	4.19%	0.70	5.32%	7.9%
PNM Resources	4.19%	0.85	5.32%	8.7%
Portland General	4.19%	0.70	5.32%	7.9%
Progress Energy	4.19%	0.65	5.32%	7.6%
Southern Company	4.19%	0.55	5.32%	7.1%
TECO Energy	4.19%	0.80	5.32%	8.4%
Unisource Energy	4.19%	0.70	5.32%	7.9%
Westar Energy	4.19%	0.75	5.32%	8.2%
Wisconsin Energy	4.19%	0.65	5.32%	7.6%
Xcel Energy Inc.	4.19%	0.65	5.32%	7.6%
Average				7.9%
Median				7.9%
Moody's Electric Utilities				
American Electric Power	4.19%	0.75	5.32%	8.2%
CH Energy	4.19%	0.65	5.32%	7.6%
Consolidated Edison	4.19%	0.65	5.32%	7.6%
Constellation Energy	4.19%	0.80	5.32%	8.4%
Dominion Resources	4.19%	0.70	5.32%	7.9%
DPL Inc	4.19%	0.60	5.32%	7.4%
DTE Energy	4.19%	0.75	5.32%	8.2%
Duke Energy	4.19%		5.32%	
Exelon Corp	4.19%	0.85	5.32%	8.7%
Firstenergy	4.19%	0.85	5.32%	8.7%
IDACORP	4.19%	0.70	5.32%	7.9%
NiSource	4.19%	0.85	5.32%	8.7%
OGE Energy	4.19%	0.75	5.32%	8.2%
PPL Corp	4.19%	0.70	5.32%	7.9%
Progress Energy	4.19%	0.65	5.32%	7.6%
Public Service Enterprise	4.19%	0.80	5.32%	8.4%
Southern Co.	4.19%	0.55	5.32%	7.1%
TECO Energy	4.19%	0.75	5.32%	8.2%
Xcel Energy Inc.	4.19%	0.65	5.32%	7.6%
Average				8.0%
Median				8.0%

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COMPARISON COMPANIES
CAPM COST RATES
USING IBBOTSON RISK PREMIUM

COMPANY	RISK-FREE RATE	BETA	MARKET PREMIUM	CAPM RATES
Comparison Group - PUC Criteria				
Empire District Electric	4.19%	0.75	5.60%	8.4%
Hawaiian Electric Industries	4.19%	0.60	5.60%	7.6%
IDACORP	4.19%	0.70	5.60%	8.1%
NV Energy	4.19%	0.90	5.60%	9.2%
Northeast Utilities	4.19%	0.70	5.60%	8.1%
NSTAR	4.19%	0.65	5.60%	7.8%
Pinnacle West Capital	4.19%	0.70	5.60%	8.1%
Pepco Holdings, Inc.	4.19%	0.80	5.60%	8.7%
Portland General	4.19%	0.70	5.60%	8.1%
SCANA Corp	4.19%	0.70	5.60%	8.1%
UIL Holdings	4.19%	0.70	5.60%	8.1%
Westar Energy	4.19%	0.75	5.60%	8.4%
Average				8.2%
Median				8.1%
Comparison Group - Parcell Criteria				
Avista	4.19%	0.70	5.60%	8.1%
Cleco Corp.	4.19%	0.70	5.60%	8.1%
Empire District Electric	4.19%	0.75	5.60%	8.4%
Hawaiian Electric Industries	4.19%	0.60	5.60%	7.6%
IDACORP	4.19%	0.70	5.60%	8.1%
NSTAR	4.19%	0.65	5.60%	7.8%
Portland General	4.19%	0.70	5.60%	8.1%
Westar Energy, Inc.	4.19%	0.75	5.60%	8.4%
Mean				8.1%
Median				8.1%
S&P Integrated Electric Utilities				
ALLETE	4.19%	0.70	5.60%	8.1%
Alliant Energy	4.19%	0.70	5.60%	8.1%
Ameren Corp.	4.19%	0.80	5.60%	8.7%
American Electric Power	4.19%	0.75	5.60%	8.4%
Cleco	4.19%	0.70	5.60%	8.1%
CMS Energy	4.19%	0.80	5.60%	8.7%
DPL	4.19%	0.60	5.60%	7.6%
DTE Energy	4.19%	0.75	5.60%	8.4%
Edison International	4.19%	0.80	5.60%	8.7%
Empire District Electric	4.19%	0.75	5.60%	8.4%
Entergy	4.19%	0.70	5.60%	8.1%
FPL Group	4.19%	0.75	5.60%	8.4%
Hawaiian Electric Industries	4.19%	0.60	5.60%	7.6%
IDACORP	4.19%	0.70	5.60%	8.1%
MGE Energy	4.19%	0.65	5.60%	7.8%
Northeast Utilities	4.19%	0.70	5.60%	8.1%
PG&E	4.19%	0.60	5.60%	7.6%
Pinnacle West Capital	4.19%	0.70	5.60%	8.1%
PNM Resources	4.19%	0.85	5.60%	9.0%
Portland General	4.19%	0.70	5.60%	8.1%
Progress Energy	4.19%	0.65	5.60%	7.8%
Southern Company	4.19%	0.55	5.60%	7.3%
TECO Energy	4.19%	0.80	5.60%	8.7%
Unisource Energy	4.19%	0.70	5.60%	8.1%
Westar Energy	4.19%	0.75	5.60%	8.4%
Wisconsin Energy	4.19%	0.65	5.60%	7.8%
Xcel Energy Inc.	4.19%	0.65	5.60%	7.8%
Average				8.1%
Median				8.1%
Moody's Electric Utilities				
American Electric Power	4.19%	0.75	5.60%	8.4%
CH Energy	4.19%	0.65	5.60%	7.8%
Consolidated Edison	4.19%	0.65	5.60%	7.8%
Constellation Energy	4.19%	0.80	5.60%	8.7%
Dominion Resources	4.19%	0.70	5.60%	8.1%
DPL Inc	4.19%	0.60	5.60%	7.6%
DTE Energy	4.19%	0.75	5.60%	8.4%
Duke Energy	4.19%		5.60%	
Exelon Corp	4.19%	0.85	5.60%	9.0%
Firstenergy	4.19%	0.85	5.60%	9.0%
IDACORP	4.19%	0.70	5.60%	8.1%
NiSource	4.19%	0.85	5.60%	9.0%
OGE Energy	4.19%	0.75	5.60%	8.4%
PPL Corp	4.19%	0.70	5.60%	8.1%
Progress Energy	4.19%	0.65	5.60%	7.8%
Public Service Enterprise	4.19%	0.80	5.60%	8.7%
Southern Co.	4.19%	0.55	5.60%	7.3%
TECO Energy	4.19%	0.75	5.60%	8.4%
Xcel Energy Inc.	4.19%	0.65	5.60%	7.8%
Average				8.2%
Median				8.3%

COMPARISON COMPANIES
RATES OF RETURN ON AVERAGE COMMON EQUITY

Company	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	1992-2001 Average	2002-2008 Average	2009	2010	2012-2014
Comparison Group - PUC Criteria																						
Empire District Electric	10.3%	9.4%	10.6%	9.4%	9.4%	9.9%	11.6%	8.4%	10.0%	4.3%	8.4%	8.7%	5.7%	6.2%	9.2%	6.9%	7.4%	9.3%	7.5%	10.0%	10.0%	11.0%
Hawaiian Electric Industries	10.9%	10.5%	11.1%	11.0%	10.5%	10.9%	11.5%	11.1%	9.8%	12.4%	11.9%	11.1%	9.3%	9.7%	9.3%	7.7%	8.1%	11.0%	9.6%	8.5%	10.0%	10.5%
IDACORP	9.0%	11.2%	10.1%	11.6%	12.1%	12.4%	12.4%	12.3%	16.7%	14.9%	7.1%	4.2%	8.2%	7.3%	9.4%	7.1%	8.2%	12.3%	7.4%	7.5%	7.5%	7.5%
NV Energy	10.2%	11.8%	11.5%	9.5%	9.6%	10.0%	9.8%	4.7%	-3.5%	2.0%	-20.3%	-9.1%	3.2%	3.8%	10.3%	7.2%	6.9%	7.6%	0.3%	5.0%	7.5%	7.5%
Northeast Utilities	12.6%	9.4%	12.6%	11.9%	0.1%	-6.2%	-2.3%	-7.3%	-1.3%	8.6%	6.4%	7.1%	5.1%	5.4%	4.5%	8.6%	9.8%	3.8%	6.7%	8.5%	9.5%	8.5%
NSTAR	11.4%	11.9%	12.2%	10.2%	12.6%	12.6%	12.5%	11.4%	12.3%	13.4%	14.0%	13.9%	13.4%	13.1%	13.2%	13.5%	13.6%	12.1%	13.5%	13.5%	14.0%	14.5%
Pinnacle West Capital	10.7%	10.9%	10.2%	10.6%	11.2%	11.9%	11.5%	12.3%	12.4%	12.8%	8.6%	8.3%	8.2%	6.7%	9.2%	8.5%	7.9%	11.5%	8.2%	7.5%	8.0%	9.0%
Pepco Holdings, Inc.	10.6%	12.0%	10.8%	10.5%	11.7%	10.5%	11.3%	11.7%	8.9%	11.9%	9.8%	7.6%	9.3%	9.1%	7.1%	7.9%	9.0%	11.0%	8.5%	7.5%	8.5%	8.5%
Portland General	12.9%	12.0%	11.3%	13.5%	13.9%										5.9%	11.5%	7.0%	12.7%	8.1%	8.5%	8.5%	9.0%
SCANA Corp	11.0%	13.5%	11.0%	11.5%	13.3%	11.7%	12.6%	7.8%	10.7%	10.7%	11.7%	12.4%	12.6%	12.4%	10.9%	11.0%	11.5%	11.4%	11.8%	10.5%	10.5%	10.5%
UIL Holdings	9.2%	10.4%	10.5%	11.8%	10.1%	10.4%	9.5%	11.6%	12.8%	12.1%	8.9%	6.1%	7.1%	5.7%	9.1%	10.0%	10.2%	10.8%	8.2%	10.0%	10.5%	11.0%
Westar Energy	11.0%	12.4%	10.7%	11.1%	10.4%	-1.6%	7.1%	5.2%	3.2%	-2.2%	5.0%	10.6%	7.7%	9.6%	11.1%	10.0%	6.6%	6.7%	8.7%	7.5%	8.0%	8.0%
Mean	10.8%	11.3%	11.0%	11.1%	10.4%	8.4%	9.8%	8.1%	8.4%	9.2%	6.5%	7.4%	8.2%	8.1%	9.1%	9.2%	8.9%	10.0%	8.2%	8.7%	9.4%	9.6%
Median	10.8%	11.5%	10.9%	11.1%	10.9%	10.5%	11.5%	11.1%	10.0%	11.9%	8.6%	8.3%	8.2%	7.3%	9.3%	8.6%	8.2%	11.0%	8.3%	8.5%	9.0%	9.0%
Comparison Group - Parcell Criteria																						
Avista	11.7%	12.2%	10.5%	11.2%	10.6%	15.0%	10.2%	1.1%	13.4%	7.9%	4.5%	6.7%	4.6%	5.8%	8.8%	4.1%	8.2%	10.4%	6.1%	8.0%	8.0%	8.0%
Cleco Corp.	14.0%	12.4%	12.9%	13.4%	13.8%	12.8%	12.6%	12.9%	15.0%	14.6%	13.5%	11.5%	12.6%	11.6%	9.4%	8.2%	9.9%	13.4%	11.0%	9.0%	10.0%	11.5%
Empire District Electric	10.3%	9.4%	10.6%	9.4%	9.4%	9.9%	11.6%	8.4%	10.0%	4.3%	8.4%	8.7%	5.7%	6.2%	9.2%	6.9%	7.4%	9.3%	7.5%	10.0%	10.0%	11.0%
Hawaiian Electric Industries	10.9%	10.5%	11.1%	11.0%	10.5%	10.9%	11.5%	11.1%	9.8%	12.4%	11.9%	11.1%	9.3%	9.7%	9.3%	7.7%	8.1%	11.0%	9.6%	8.5%	10.0%	10.5%
IDACORP	9.0%	11.2%	10.1%	11.6%	12.1%	12.4%	12.4%	12.3%	16.7%	14.9%	7.1%	4.2%	8.2%	7.3%	9.4%	7.1%	8.2%	12.3%	7.4%	7.5%	7.5%	7.5%
NSTAR	11.4%	11.9%	12.2%	10.2%	12.6%	12.6%	12.5%	11.4%	12.3%	13.4%	14.0%	13.9%	13.4%	13.1%	13.2%	13.5%	13.6%	12.1%	13.5%	13.5%	14.0%	14.5%
Portland General	12.9%	12.0%	11.3%	13.5%	13.9%										5.9%	11.5%	7.0%	12.7%	8.1%	8.5%	8.5%	9.0%
Westar Energy, Inc.	11.0%	12.4%	10.7%	11.1%	10.4%	-1.6%	7.1%	5.2%	3.2%	-2.2%	5.0%	10.6%	7.7%	9.6%	11.1%	10.0%	6.6%	6.7%	8.7%	7.5%	8.0%	8.0%
Mean	11.4%	11.5%	11.2%	11.4%	11.7%	10.3%	11.1%	8.9%	11.5%	9.3%	9.2%	9.5%	8.8%	9.0%	9.5%	8.6%	8.6%	11.0%	9.0%	9.1%	9.5%	10.0%
Median	11.2%	12.0%	10.9%	11.2%	11.3%	12.4%	11.6%	11.1%	12.3%	12.4%	8.4%	10.6%	8.2%	9.6%	9.4%	8.0%	8.2%	11.6%	8.9%	8.5%	9.3%	9.8%

S&P Integrated
Electric Utilities

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COMPARISON COMPANIES
MARKET TO BOOK RATIOS

Company	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	1992-2001 Average	2002-2008 Average
Comparison Group - PUC Criteria																			
Empire District Electric	184%	178%	143%	142%	143%	138%	168%	177%	183%	162%	132%	133%	144%	148%	149%	150%	118%	162%	139%
Hawaiian Electric Industries	171%	154%	141%	149%	147%	147%	154%	132%	127%	145%	153%	151%	179%	181%	192%	166%	164%	147%	169%
IDACORP	155%	172%	146%	148%	168%	177%	177%	158%	189%	185%	134%	112%	125%	122%	139%	132%	104%	168%	124%
NV Energy	148%	165%	133%	130%	131%	143%	147%	123%	87%	82%	72%	41%	68%	106%	136%	137%	91%	129%	93%
Northeast Utilities	154%	149%	127%	124%	95%	64%	91%	113%	136%	129%	99%	95%	106%	108%	131%	163%	128%	118%	119%
NSTAR	138%	154%	130%	130%	125%	146%	181%	166%	161%	161%	170%	175%	189%	202%	214%	222%	201%	149%	196%
Pinnacle West Capital	116%	125%	99%	116%	133%	152%	180%	143%	145%	154%	116%	114%	130%	130%	129%	127%	97%	136%	120%
Pepco Holdings, Inc.	160%	162%	135%	138%	161%	151%	161%	166%	139%	124%	110%	103%	109%	122%	129%	141%	110%	150%	118%
Portland General	115%	125%	112%	140%	199%										153%	140%	101%	138%	131%
SCANA Corp	161%	168%	157%	166%	175%	164%	195%	145%	134%	135%	137%	158%	171%	179%	167%	158%	141%	160%	150%
UIL Holdings	123%	157%	127%	123%	114%	111%	151%	144%	141%	139%	126%	113%	133%	135%	174%	187%	167%	133%	148%
Westar Energy	144%	152%	130%	129%	126%	131%	128%	89%	74%	78%	67%	109%	132%	142%	139%	140%	106%	118%	119%
Mean	147%	155%	132%	136%	143%	139%	158%	141%	138%	138%	120%	119%	135%	143%	154%	155%	127%	142%	136%
Median	151%	156%	132%	134%	138%	146%	161%	144%	139%	139%	126%	113%	132%	135%	144%	146%	114%	144%	130%
Comparison Group - Parcell Criteria																			
Avista	151%	163%	133%	125%	145%	162%	163%	152%	317%	114%	85%	94%	111%	115%	135%	127%	110%	163%	111%
Cleco Corp.	177%	175%	156%	162%	168%	171%	183%	172%	223%	224%	154%	134%	177%	177%	162%	162%	133%	181%	157%
Empire District Electric	184%	178%	143%	142%	143%	138%	168%	177%	183%	162%	132%	133%	144%	148%	149%	150%	118%	162%	139%
Hawaiian Electric Industries	171%	154%	141%	149%	147%	147%	154%	132%	127%	145%	153%	151%	179%	181%	192%	166%	164%	147%	169%
IDACORP	155%	172%	146%	148%	168%	177%	177%	158%	189%	185%	134%	112%	125%	122%	139%	132%	104%	168%	124%
NSTAR	138%	154%	130%	130%	125%	146%	181%	166%	161%	161%	170%	175%	189%	202%	214%	222%	201%	149%	196%
Portland General	115%	125%	112%	140%	199%										153%	140%	101%	138%	131%
Westar Energy, Inc.	144%	152%	130%	129%	126%	131%	128%	89%	74%	78%	67%	109%	132%	142%	139%	140%	106%	118%	119%
Mean	154%	159%	136%	141%	153%	153%	165%	149%	182%	153%	128%	130%	151%	155%	160%	155%	130%	153%	143%
Median	153%	159%	137%	141%	146%	147%	168%	158%	183%	161%	134%	133%	144%	148%	151%	145%	114%	156%	138%
S&P Integrated Electric Utilities																			
ALLETE														212%	219%	195%	156%		196%
Alliant Energy	190%	185%	154%	152%	154%	155%	156%	120%	120%	129%	110%	97%	120%	131%	155%	173%	131%	152%	131%
Ameren Corp.	169%	188%	160%	170%	175%	174%	180%	167%	163%	173%	163%	162%	161%	172%	164%	159%	125%	172%	158%
American Electric Power	143%	159%	143%	156%	176%	187%	191%	154%	147%	179%	138%	124%	155%	165%	161%	190%	145%	164%	154%
Cleco	177%	175%	156%	162%	168%	171%	183%	172%	223%	224%	154%	134%	177%	177%	162%	162%	133%	181%	157%
CMS Energy	168%	223%	185%	182%	181%	200%	221%	189%	119%	152%	137%	80%	90%	125%	142%	175%	126%	182%	125%
DPL	177%	206%	196%	213%	214%	221%	231%	215%	314%	422%	322%	241%	272%	318%	373%	415%	298%	241%	320%
DTE Energy	162%	154%	120%	130%	137%	126%	165%	145%	126%	142%	145%	142%	132%	140%	134%	143%	101%	141%	134%
Edison International	167%	172%	122%	116%	120%	158%	192%	173%	197%	128%	117%	108%	153%	205%	194%	208%	154%	155%	163%
Empire District Electric	184%	178%	143%	142%	143%	138%	168%	177%	183%	162%	132%	133%	144%	148%	149%	150%	118%	162%	139%
Entergy	124%	137%	104%	88%	97%	95%	99%	99%	99%	118%	114%	136%	156%	194%	211%	264%	226%	106%	186%
FPL Group	173%	180%	151%	175%	184%	198%	234%	177%	177%	186%	160%	167%	174%	201%	203%	249%	199%	184%	193%
Hawaiian Electric Industries	171%	154%	141%	149%	147%	147%	154%	132%	127%	145%	153%	151%	179%	181%	192%	166%	164%	147%	169%
IDACORP	155%	172%	146%	148%	168%	177%	177%	158%	189%	185%	134%	112%	125%	122%	139%	132%	104%	168%	124%
MGE Energy	189%	196%	189%	183%	203%	189%	197%	177%	172%	197%	214%	223%	207%	207%	191%	178%	160%	189%	197%
Northeast Utilities	154%	149%	127%	124%	95%	64%	91%	113%	136%	129%	99%	95%	106%	108%	131%	163%	128%	118%	119%
PG&E	168%	175%	142%	134%	115%	123%	152%	135%	179%	136%	149%	203%	196%	179%	201%	203%	144%	146%	182%
Pinnacle West Capital	116%	125%	99%	116%	133%	152%	180%	143%	145%	154%	116%	114%	130%	130%	129%	127%	97%	136%	120%
PNM Resources	72%	84%	87%	95%	108%	106%	106%	85%	94%	123%	95%	93%	124%	147%	134%	125%	67%	96%	112%
Portland General	115%	125%	112%	140%	199%										153%	140%	101%	138%	131%
Progress Energy	171%	192%	159%	181%	209%	207%	233%	189%	163%	164%	152%	145%	144%	137%	140%	148%	125%	187%	142%
Southern Company	154%	180%	161%	174%	176%	167%	198%	186%	188%	209%	230%	233%	227%	238%	229%	230%	211%	179%	228%
TECO Energy	243%	268%	224%	238%	241%	234%	247%	210%	223%	222%	135%	111%	174%	243%	202%	188%	174%	235%	175%
Unisource Eneregy	NMF	NMF	NMF	NMF	NMF	295%	217%	138%	143%	167%	134%	141%	145%	171%	185%	177%	144%	192%	157%
Westar Energy	144%	152%	130%	129%	126%	131%	128%	89%	74%	78%	67%	109%	132%	142%	139%	140%	106%	118%	119%

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STANDARD & POOR'S 500 COMPOSITE RETURNS AND MARKET-TO-BOOK RATIOS 1992 - 2007

YEAR	RETURN ON AVERAGE EQUITY	MARKET-TO BOOK RATIO
1992	12.2%	271%
1993	13.2%	272%
1994	16.4%	246%
1995	16.6%	264%
1996	17.1%	299%
1997	16.3%	354%
1998	14.6%	421%
1999	17.3%	481%
2000	16.2%	453%
2001	7.5%	353%
2002	8.4%	296%
2003	14.2%	278%
2004	15.0%	291%
2005	16.1%	278%
2006	17.0%	277%
2007	12.8%	284%
Averages:		
1992-2001	14.7%	341%
2001-2005	13.9%	284%

Source: Standard & Poor's Analyst's Handbook, 2008 edition, page 1.

RISK INDICATORS

GROUP	VALUE LINE SAFETY	VALUE LINE BETA	VALUE LINE FIN STR	S & P STK RANK
S & P's 500 Composite	2.7	1.05	B++	B+
Comparison Group - PUC Criteria	2.4	0.72	B++	B
Comparison Group - Parcell Criteria	2.4	0.69	B++	B
Hawaiian Electric Industries	2.0	0.60	B+	B

Sources: Value Line Investment Survey, Standard & Poor's Stock Guide.

Definitions:

Safety rankings are in a range of 1 to 5, with 1 representing the highest safety or lowest risk.

Beta reflects the variability of a particular stock, relative to the market as a whole. A stock with a beta of 1.0 moves in concert with the market, a stock with a beta below 1.0 is less variable than the market, and a stock with a beta above 1.0 is more variable than the market.

Financial strengths range from C to A++, with the latter representing the highest level.

Common stock rankings range from D to A+, with the latter representing the highest level.

HAWAIIAN ELECTRIC COMPANY
RATING AGENCY RATIOS

ITEM	AMOUNT ($000)	PERCENT	COST RATE	WEIGHTED COST	PRE-TAX COST
Short-Term Debt	$21,951	1.16%	0.00%	0.00%	0.00%
Long-Term Debt	$561,940	29.58%	5.81%	1.72%	1.72%
Purchased Power (1)	$431,033	22.69%	10.00%	2.27%	2.27%
Hybrid Securities	$27,775	1.46%	7.41%	0.11%	0.11%
Preferred Stock	$59,496	3.13%	5.48%	0.17%	0.29%
Common Equity	$797,307	41.97%	9.50%	3.99%	6.65%
TOTAL CAPITAL	$1,899,502	100.00%		8.26%	11.03%

(1) Average 2009 Purchased Power 'debt equivalent" from HECO-WP-2016, page 14.

Pre-tax coverage = 11.03%/(1.72%+2.27%)
2.77 X

Standard & Poor's Utility Benchmark Ratios:

	A	BBB
Pre-tax coverage (X) Business Position:		
5	3.5 - 4.3x	2.4 - 3.5x
Total Debt to Total Capital (%) Business Position		
5	42 - 50%	50 - 60%

Note: Since 2004, S&P no longer uses the ratio "Pre-tax Coverage" as one of its benchmark ratios. The benchmark levels shown above reflect the 1999 levels cited by S&P.

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YIELD DIFFERENTIALS BETWEEN Baa AND A RATED SECURITIES

	Bonds			Preferred Stocks		
	Baa	A	Difference	Baa	A	Difference
2001						
Jan	7.99%	7.80%	0.19%	7.53%	7.42%	0.11%
Feb	7.94%	7.74%	0.20%	7.48%	7.38%	0.10%
Mar	7.85%	7.68%	0.17%	7.48%	7.35%	0.13%
Apr	8.06%	7.94%	0.12%	7.59%	7.47%	0.12%
May	8.11%	7.99%	0.12%	7.57%	7.48%	0.09%
June	8.02%	7.85%	0.17%	7.60%	7.36%	0.24%
July	8.05%	7.78%	0.27%	7.42%	7.25%	0.17%
Aug	7.95%	7.59%	0.36%	7.40%	7.07%	0.33%
Sept	8.12%	7.75%	0.37%	7.41%	7.17%	0.24%
Oct	8.02%	7.63%	0.39%	7.40%	7.06%	0.34%
Nov	7.96%	7.57%	0.39%	7.53%	7.17%	0.36%
Dec	8.27%	7.83%	0.44%	7.66%	7.30%	0.36%
2002						
Jan	8.13%	7.66%	0.47%	7.62%	7.30%	0.32%
Feb	8.18%	7.54%	0.64%	7.51%	7.22%	0.29%
Mar	8.32%	7.76%	0.56%	7.83%	7.36%	0.47%
Apr	8.26%	7.57%	0.69%	7.62%	7.27%	0.35%
May	8.33%	7.52%	0.81%	7.62%	7.29%	0.33%
June	8.26%	7.42%	0.84%	7.74%	7.40%	0.34%
July	8.07%	7.31%	0.76%	7.64%	7.33%	0.31%
Aug	7.74%	7.17%	0.57%	7.42%	7.20%	0.22%
Sept	7.62%	7.08%	0.54%	7.46%	7.16%	0.30%
Oct	8.00%	7.23%	0.77%	7.59%	7.37%	0.22%
Nov	7.76%	7.14%	0.62%	7.56%	7.38%	0.18%
Dec	7.61%	7.07%	0.54%	7.57%	7.06%	0.51%
2003						
Jan	7.47%	7.06%	0.41%	7.61%	7.13%	0.48%
Feb	7.17%	6.93%	0.24%	7.62%	7.01%	0.61%
Mar	7.05%	6.79%	0.26%	7.66%	7.05%	0.61%
Apr	6.94%	6.64%	0.30%	7.51%	6.97%	0.54%
May	6.47%	6.36%	0.11%	7.42%	6.83%	0.59%
June	6.30%	6.21%	0.09%	7.41%	6.81%	0.60%
July	6.67%	6.57%	0.10%	7.24%	6.84%	0.40%
Aug	7.08%	6.78%	0.30%	7.29%	6.77%	0.52%
Sept	6.87%	6.56%	0.31%	7.28%	6.73%	0.55%
Oct	6.79%	6.43%	0.36%	7.26%	6.87%	0.39%
Nov	6.69%	6.37%	0.32%	7.29%	6.84%	0.45%
Dec	6.61%	6.27%	0.34%	7.28%	6.70%	0.58%
2004						
Jan	6.47%	6.15%	0.32%	7.20%	6.65%	0.55%
Feb	6.28%	6.15%	0.13%	7.20%	6.71%	0.49%
Mar	6.12%	5.97%	0.15%	7.20%	6.70%	0.50%
Apr	6.46%	6.35%	0.11%	7.27%	7.10%	0.17%
May	6.75%	6.62%	0.13%	7.64%	7.42%	0.22%
June	6.84%	6.46%	0.38%	7.17%	7.00%	0.17%
July	6.67%	6.27%	0.40%	6.89%	6.64%	0.25%
Aug	6.45%	6.14%	0.31%	6.74%	6.38%	0.36%
Sept	6.27%	5.98%	0.29%	6.61%	6.24%	0.37%
Oct	6.17%	5.94%	0.23%	6.53%	6.26%	0.27%
Nov	6.16%	5.97%	0.19%	6.23%	6.19%	0.04%
Dec	6.10%	5.92%	0.18%	6.42%	6.16%	0.26%
2005						
Jan	5.95%	5.78%	0.17%	6.35%	6.15%	0.20%
Feb	5.76%	5.61%	0.15%	6.36%	6.29%	0.07%
Mar	6.01%	5.83%	0.18%	6.42%	6.41%	0.01%
Apr	5.95%	5.64%	0.31%	6.41%	6.17%	0.24%
May	5.88%	5.53%	0.35%	6.39%	6.24%	0.15%
June	5.70%	5.40%	0.30%	6.37%	6.20%	0.17%
July	5.81%	5.51%	0.30%	6.35%	6.22%	0.13%
Aug	5.80%	5.50%	0.30%	6.36%	6.21%	0.15%
Sept	5.83%	5.52%	0.31%	6.38%	6.27%	0.11%
Oct	6.08%	5.79%	0.29%	6.40%	6.41%	-0.01%
Nov	6.19%	5.88%	0.31%	6.45%	6.31%	0.14%
Dec	6.14%	5.80%	0.34%	6.42%	6.19%	0.23%
2006						
Jan	6.06%	5.75%	0.31%	6.41%	6.14%	0.27%
Feb	6.11%	5.82%	0.29%	6.38%	6.10%	0.28%
Mar	6.26%	5.98%	0.28%	6.56%	6.22%	0.34%
Apr	6.54%	6.29%	0.25%	6.64%	6.31%	0.33%
May	6.59%	6.42%	0.17%	6.57%	6.32%	0.25%
June	6.61%	6.40%	0.21%	6.63%	6.38%	0.25%
July	6.61%	6.37%	0.24%	6.42%	6.25%	0.17%
Aug	6.43%	6.20%	0.23%	6.37%	6.19%	0.18%
Sept	6.26%	6.00%	0.26%	6.36%	6.22%	0.14%
Oct	6.24%	5.98%	0.26%	6.23%	6.02%	0.21%
Nov	6.04%	5.80%	0.24%	6.23%	6.01%	0.22%
Dec	6.05%	5.81%	0.24%	6.17%	5.90%	0.27%
2007						
Jan	6.16%	5.96%	0.20%	6.08%	5.90%	0.18%
Feb	6.10%	5.90%	0.20%	6.04%	5.85%	0.19%
Mar	6.10%	5.85%	0.25%	6.03%	5.76%	0.27%
Apr	6.24%	5.97%	0.27%	6.12%	5.81%	0.31%
May	6.23%	5.99%	0.24%	6.16%	5.88%	0.28%
June	6.54%	6.30%	0.24%	6.23%	6.13%	0.10%
July	6.49%	6.25%	0.24%	6.51%	6.29%	0.22%
Aug	6.51%	6.24%	0.27%	6.24%	6.09%	0.15%
Sept	6.45%	6.18%	0.27%	6.24%	6.12%	0.12%
Oct	6.36%	6.11%	0.25%	6.27%	6.18%	0.09%
Nov	6.27%	5.97%	0.30%	6.37%	6.17%	0.20%
Dec	6.51%	6.16%	0.35%	6.51%	6.20%	0.31%
2008						
Jan	6.35%	6.02%	0.33%	6.37%	5.97%	0.40%
Feb	6.60%	6.21%	0.39%	6.32%	5.84%	0.48%
Mar	6.68%	6.21%	0.47%	6.52%	5.95%	0.57%
Apr	6.81%	6.29%	0.52%	6.62%	5.98%	0.64%
May	6.79%	6.27%	0.52%	6.52%	6.02%	0.50%
June	6.93%	6.38%	0.55%	6.64%	5.99%	0.65%
July	6.97%	6.40%	0.57%	6.68%	5.95%	0.73%
Aug	6.98%	6.37%	0.61%	6.71%	6.03%	0.68%
Sept	7.15%	6.49%	0.66%	6.86%	6.24%	0.62%
Oct	8.58%	7.56%	1.02%	7.20%	6.70%	0.50%
Nov	8.98%	7.60%	1.38%	7.76%	6.85%	0.91%
Dec	8.13%	6.54%	1.59%	7.55%	6.58%	0.97%
2009						
Jan	7.90%	6.39%	1.51%	7.14%	6.38%	0.76%
Feb	7.74%	6.30%	1.44%	7.25%	6.48%	0.77%
Mar	8.00%	6.42%	1.58%	7.42%	6.32%	1.10%
Apr	8.03%	6.48%	1.55%	7.40%	6.21%	1.19%
May	7.76%	6.49%	1.27%	7.23%	6.20%	1.03%
Average			0.42%			0.35%

Source: Mergent Bond Record.

RISK PREMIUM BY DECADE AS DERIVED BY HECO WITNESS MORIN

Year	Risk Premium	Risk Premium By Decade
1932	-21.32%	
1933	-22.79%	
1934	-31.59%	
1935	72.01%	
1936	14.27%	
1937	-37.48%	
1938	13.62%	
1939	3.51%	-1.22%
1940	-25.08%	
1941	-34.06%	
1942	20.33%	
1943	55.10%	
1944	4.01%	
1945	43.97%	
1946	9.91%	
1947	-14.14%	
1948	5.33%	
1949	16.16%	8.15%
1950	7.15%	
1951	20.72%	
1952	18.32%	
1953	6.62%	
1954	22.43%	
1955	9.27%	
1956	8.24%	
1957	1.09%	
1958	42.03%	
1959	7.79%	14.17%
1960	7.17%	
1961	33.94%	
1962	-6.66%	
1963	8.50%	
1964	13.16%	
1965	2.20%	
1966	-7.93%	
1967	4.38%	
1968	9.92%	
1969	-10.60%	5.41%
1970	-0.93%	
1971	-10.38%	
1972	-2.27%	
1973	-13.87%	
1974	-28.22%	
1975	44.15%	
1976	11.66%	
1977	12.32%	
1978	-2.88%	
1979	5.74%	1.53%
1980	12.25%	
1981	15.63%	
1982	3.61%	
1983	10.64%	
1984	8.87%	
1985	-1.27%	
1986	2.89%	
1987	-5.07%	
1988	6.97%	
1989	10.99%	6.55%
1990	-2.20%	
1991	9.61%	
1992	-3.65%	
1993	-4.82%	
1994	-7.31%	
1995	0.98%	
1996	3.11%	
1997	6.25%	
1998	8.62%	
1999	-10.32%	0.03%
2000	50.09%	
2001	-11.34%	
2002	-28.38%	
2003	22.25%	
2004	20.51%	
2005	10.95%	
2006	17.25%	11.62%

Source: HECO-1902.

COMPARISON OF DCF AND CAPM ANALYSES OF CONSUMER ADVOCATE WITNESS PARCELL AS SHOWN IN DIRECT TESTIMONY AND UPDATED TO CONFORM WITH CRITICISM OF HECO WITNESS MORIN AS DESCRIBED IN HIS REBUTTAL TESTIMONY

	DCF Analyses			CAPM Analyses			
	Direct CA-408 Page 4 1/	Update CA-408 Page 4 2/	Modified CA-408 Page 4	Direct CA-410 Page1 1/	Update CA-410 Page 1 4/	Direct CA-410 Page2 1/	Update CA-410 Page 2 4/
PUC Proxy Group							
Mean	10.1%	10.5%	10.1%	7.4%	8.0%	7.6%	8.0%
Median	10.3%	10.5%	10.0%	7.2%	7.9%	7.4%	7.9%
Mean Low	8.8%	9.4%	9.0%				
Mean High	12.1%	12.6%	12.2%				
Median Low	8.7%	9.3%	9.0%				
Median High	11.1%	12.2%	11.9%				
Parcell Proxy Group							
Mean	10.0%	10.5%	10.1%	7.4%	7.9%	7.6%	7.9%
Median	10.2%	10.5%	10.5%	7.3%	7.9%	7.6%	7.9%
Mean Low	8.4%	9.4%	8.6%				
Mean High	12.5%	12.6%	12.0%				
Median Low	8.3%	9.3%	8.4%				
Median High	10.8%	12.2%	11.1%				
S&P Integrated Group							
Mean	10.7%	10.7%	10.5%	7.4%	7.9%	7.6%	7.9%
Median	10.5%	10.7%	10.1%	7.5%	7.9%	7.7%	7.9%
Mean Low	9.6%	9.6%	9.4%				
Mean High	12.4%	12.0%	11.9%				
Median Low	8.9%	9.1%	9.1%				
Median High	11.4%	11.7%	11.6%				
Moody's Electric Utilities							
Mean	11.0%	10.9%	10.6%	7.3%	8.0%	7.5%	8.0%
Median	11.2%	10.5%	10.1%	7.2%	8.0%	7.4%	8.0%
Mean Low	10.5%	10.5%	10.2%				
Mean High	12.5%	12.1%	11.8%				
Median Low	9.6%	9.8%	9.6%				
Median High	11.4%	11.5%	11.2%				

1/ As contained in CA-T-4, Direct Testimony of David C. Parcell.

2/ Updated using average stock prices for three-month period April - June, 2009, mostrecent issues of Value Line, and end-of-June, 2009 analysts' forecasts of EPS.

3/ "Modified" to use spot stock prices as of July 6, 2009, to conform with yield procudure used by HECO witness Morin. Also used most recent issues of Value Line and end-of-June, 2009 analysts' forecasts of EPS.

4/ Updated using 20-year U.S.Treasury bond yields for three-month period April - June, 2009 and most recent issues of Value Line for betas.

ST-5

M. BROSCH

CA-ST-5
DOCKET NO. 2008-0083

SUPPLEMENTAL TESTIMONY AND EXHIBITS

OF

MICHAEL L. BROSCH

ON BEHALF OF
THE DIVISION OF CONSUMER ADVOCACY

SUBJECT: **Cost of Service Studies, Revenue Increase Distribution, Rate Increase Implementation.**

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Q. PLEASE STATE YOUR NAME.

A. My name is Michael L. Brosch.

Q HAVE YOU SUBMITTED TESTIMONY IN THE INSTANT PROCEEDING ON BEHALF OF THE DIVISION OF CONSUMER ADVOCACY, HEREINAFTER REFERRED TO AS CONSUMER ADVOCATE?

A. Yes. I previously submitted testimony designated as CA-T-1 and CA-T-5 in this proceeding, addressing revenue requirements and cost of service/rate design, respectively. My qualifications are summarized in CA-100 which was previously filed with the CA-T-1 testimony.

Q, WHAT IS THE PURPOSE OF THE SUPPLEMENTAL TESTIMONY THAT YOU ARE NOW SPONSORING?

A. This supplemental testimony addresses the Class Cost of Service ("CCOS") and rate design questions that were raised by the Commission in its Interim Decision and Order ("ID&O") filed on July 2, 2009 in this Docket. In particular, this testimony is responsive to Part III.(f) and III.(h) where concerns were expressed by the Commission regarding certain rate design and cost allocation/revenue distribution issues. I will first address the questions raised in the ID&O associated with Time-of-Use ("TOU") rates and energy efficiency in Part III.(f). In this testimony I will also explain how cost of service results were developed and employed to determine the revenue distribution proposed in the Stipulated Settlement Letter at Exhibit 1, pages 84 and 85, all in response to Part III.(h). I have separately prepared CA-ST-1 which addresses specific revenue requirement matters raised in the ID&O.

Q. HAVE YOU PREPARED ANY EXHIBITS IN CONNECTION WITH THIS SUPPLEMENTAL TESTIMONY?

A. Yes. I prepared Exhibit CA-S-500 to illustrate the settlement revenue distribution percentages among customer classes, set forth next to the HECO Updated Cost of Service Study results. This Exhibit will be used in my testimony to explain and illustrate how the negotiated revenue distribution percentages in the Stipulated Settlement Letter compare to CCOS Study results at currently effective rates and why such revenue increase percentages are reasonable in relation to indicated cost of service.

I. <u>TIME OF USE AND ADVANCED METERING RATE DESIGN ISSUES.</u>

Q. WHAT CONCERNS WERE RAISED BY THE COMMISSION IN PART III.(f) OF THE ID&O?

A. This paragraph of the ID&O asks three questions in connection with the Rate Design proposals in this proceeding:

i) Are the time-of-use ("TOU") rates incorporated in rate design for the purpose of incenting off-peak use and dis-incenting on-peak use?

ii) Is this the proper proceeding to consider TOU, or should it be more appropriately considered in the AMI docket?

iii) Can the State make progress toward energy efficiency through rate design without AMI?

This section of my Supplemental Testimony is intended to be responsive to these questions.

Q. IS THE PURPOSE OF TOU RATES TO PROVIDE ECONOMIC INCENTIVES TO ENCOURAGE CUSTOMERS TO SHIFT THEIR ENERGY USAGE FROM PEAK PERIODS TO OFF-PEAK PERIODS?

A. Yes. The presently effective HECO tariff contains optional Schedule TOU-R and Schedule TOU-C rates that were approved in Docket No. 04-0113 for residential and commercial customers on Oahu, respectively.[1] These existing rates provide declining prices across three defined rate periods; a Priority Peak Period, a Mid-Peak Period and an Off-Peak period, which periods generally correlate with weekday evenings from 5:00 to 9:00 pm, weekday daylight hours 7:00 am to 5:00 pm and night hours from 9:00 pm to 7:00 am.[2] Customers who elect to participate have an opportunity to reduce their bills by

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1 See HECO-105, pages 81-87 for these Schedules. At present, the TOU-R rate is limited to 1,000 customers because of the complex meter data analysis and billing complexities that cannot be automated under the Company's existing Customer Information System.

2 The "Mid-peak" periods extend from 7:00 am to 9:00 pm on weekends.

shifting energy usage away from the Priority and Mid-Peak periods toward the lower priced periods.

Q. HAVE TOU RATES ALSO BEEN PROPOSED FOR MECO AND HELCO?

A. Yes. TOU rates similar to the existing HECO tariff were part of the proposed final rate design for both of these Companies in the last round of rate cases. All three HECO Companies also have a series of commercial rate riders designated as Rider T (Time of Day Rider), Rider M (Off-Peak and Curtailable Service) and Rider I (Interruptible Contract Service) that have been in place for many years and that allow participating commercial customers to shift or curtail loads in return for pricing concessions that are provided for in those tariff riders.[3]

Q. HAS HECO PROPOSED ANY REVISIONS TO THE TERMS OF ITS TOU RATES IN THIS DOCKET NO. 2008-0083?

A. Yes. HECO witness Mr. Young explains the proposed changes at HECO T-22, pages 41 to 46. The Consumer Advocate did not object to Mr. Young's proposed changes, which generally serve to simplify the TOU-R

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3 See HECO-105 at pages 36-44.

rate periods and to expand the differentials between periods to provide a greater economic incentive for residential customers to move usage off-peak.[4]

Q. ARE RATE CASES THE PROPER FORUM WITHIN WHICH TOU RATES SHOULD BE CONSIDERED, OR WOULD THE ADVANCED METERING INFRASTRUCTURE DOCKET BE A MORE APPROPRIATE FORUM?

A. Rate cases are the proper forum for consideration of TOU rate design, because in rate cases the most current and relevant costing information is available and relationships between the TOU rates and corresponding non-TOU rates can be maintained. Additionally, in rates cases the revenue impacts of any changes in TOU pricing can be considered in the development of the overall proposed rate revenues of the utility.

In contrast, the AMI Docket is necessarily concerned with the broader issues surrounding overall projected AMI project costs, project risks, projected expense savings and any energy efficiency benefits anticipated to result from specific technology deployment plans. It is possible and may be desirable to conduct focused pricing studies to evaluate customer responsiveness to alternative new time-sensitive pricing schemes that may be enabled by AMI. If such studies are done as a pilot study introduced through an application filed

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4 CA-T-5, pages 50-52.

with the Commission, the Consumer Advocate would most likely recommend that the results of the pilot should be considered in the utility's next rate proceeding, especially if the pricing schemes do not produce revenue neutral results. Thus, the AMI Docket, or any proceeding other than a rate proceeding, is not the ideal place to establish or materially change TOU rate and revenue levels.

Q. IN YOUR OPINION, CAN THE STATE MAKE PROGRESS TOWARD ENERGY EFFICIENCY THROUGH RATE DESIGN WITHOUT AMI?

A. Yes. Beyond the existing and proposed TOU rate design tariffs discussed above, HECO has proposed and the Consumer Advocate has supported the implementation of inclining block rates for HECO, HELCO and MECO residential customers in all of the pending rate case proceedings. Inclining block rates encourage customer conservation by placing higher prices upon the tail block of the rate, where incremental or decremental usage is likely to occur. Additionally, in the instant HECO Docket No. 2008-0083, the proposed final rate design in Stipulated Settlement Letter Exhibit HECO T-22, Attachment 2 contained several additional changes that are supportive of energy efficiency:

- Schedule R and Schedule J Customer Charges were reduced from HECO's proposed levels.[5] Lower customer charges force more of the revenue recovery into tariff elements that change with usage, thereby encouraging conservation.[6]
- Schedule J and Schedule P three-step declining block energy rates were simplified, adopting a single block energy rate.[7] Declining block rates can have the effect of promoting higher energy usage, which is contrary to conservation objectives.
- The Schedule P three-step declining block demand charge was also simplified, in favor of a single demand charge rate.[8] The removal of declining block rates is consistent with promotion of conservation rather than higher consumption.

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5 Stipulated Settlement Letter, HECO T-22, Attachment 2, page 1. See also CA-T-5, pages 40-41, 43-45.

6 The Consumer Advocate acknowledges that the recovery of fixed costs through usage sensitive rate elements is an issue that concerns the Commission, as evidenced in the discussion on page 16 of the ID&O. This issue is discussed further in section III., Rate Increase Implementation.

7 See HECO T-22, pages 31 and 33. The Consumer Advocate supported these HECO rate design proposals.

8 Id. page 33.

Q. CAN THE DEPLOYMENT OF ADVANCED METERING INFRASTRUCTURE ENABLE BROADER AVAILABILITY OF MORE COMPLEX ENERGY EFFICIENCY RATE DESIGNS?

A. Yes. A number of more complex pricing approaches can be undertaken, combining the AMI-related technology capabilities with combinations of more exotic rate designs intended to promote energy efficiency. Experimental rate design options can be tested by comparing traditional flat energy rates to inclining block rates, TOU rates, critical peak pricing, day-ahead real time pricing, and alternative peak-time rebates. However, customer responsiveness to more exotic pricing options is highly dependent upon customers' commitment to invest personal time and effort into energy management activities, customers' access to needed technology to understand pricing signals and intensive customer education programs. The testing of these more complex rate structures may require additional AMI investments including in-home displays of energy use and pricing data, programmable controllable end-use appliances and/or internet web presentment of such data. It is difficult to predict whether any of these customer applications would be effective in achieving cost-effective energy efficiency gains without conducting customer responsiveness pilot testing after the needed AMI technologies have been installed.

II. <u>COST ALLOCATIONS - REVENUE INCREASE DISTRIBUTION.</u>

Q. IN THE INTERIM DECISION AND ORDER, THE COMMISSION EXPRESSED CONCERN ABOUT THE STIPULATED ALLOCATION OF THE REVENUE INCREASES IN THIS DOCKET. WERE YOU INVOLVED IN THE ANALYSIS OF COST ALLOCATIONS AND THE NEGOTIATED STIPULATED DISTRIBUTION OF REVENUE INCREASES?

A. Yes. My testimony on these subjects was presented in CA-T-5 that was filed on April 30, 2009. I also assisted the Consumer Advocate in support of *negotiation of the Stipulated revenue increase distribution among customer* classes.

Q. WAS THERE A SINGLE CCOS STUDY PERFORMED IN THIS CASE, WHICH SERVED AS THE BASIS FOR THE STIPULATED REVENUE INCREASE DISTRIBUTION?

A. No. In recent rate cases, HECO has been presenting two CCOS scenarios for consideration by the Commission, as a direct result of past disputes and settlements with the Consumer Advocate. The Consumer Advocate has contested one significant CCOS methodology issue throughout all recent rate cases involving the HECO Companies. This issue involves how electric distribution network costs, including poles, conductors and line transformers, are classified either using:

- A theoretical minimum system approach that estimates a portion of such costs to be treated as a "customer" cost to be allocated based on the number of customers; or
- Treating all distribution network costs as a "demand" related cost, without theoretical minimum system conventions to estimate a customer component of such costs.

I will not repeat the arguments associated with this theoretical debate, but would refer the Commission to my testimony at CA-T-5, pages 15 through 32.

Q. IN THE ID&O, THE COMMISSION STATED THAT THE REVENUE INCREASE DISTRIBUTION PERCENTAGES IN THE STIPULATION, "...APPEAR TO DEPART FROM THE TRADITIONAL FUNCTIONALIZATION, CLASSIFICATION, AND ALLOCATION METHODOLOGY USED TO DETERMINE RATES FOR EACH CUSTOMER CLASS." HOW DO YOU RESPOND?

A. I would first observe that in my experience CCOS studies, even where there is complete agreement upon cost classification methodologies, are never rigidly followed to determine the precise class assignments of revenue increase responsibility. Instead, CCOS studies are used as a guide for distribution of a utility revenue increase among customer classes. This non-rigid approach with the CCOS study serving as a guide is evident throughout all of the relevant testimony in this Docket. For example, HECO witness Mr. Young lists, at HECO T-22, page 22, a total of nine "factors" that are considered in developing the Company's proposed rates, with CCOS results appearing as number two on that listing. Similarly, in my revenue distribution testimony in this Docket, I noted that HECO was proposing an equal percentage revenue increase to all customer classes and indicated the Consumer Advocate's support for that approach, observing that "Existing class ROR results at current interim rates are not seriously disparate now and are projected by HECO to move closer to parity under an equal percentage distribution of the rate increase."[9]

Second, the many judgments and estimates involved in preparing a CCOS argue against rigid adherence to any particular study result. There is no single consensus CCOS methodology in this Docket. Even if there were a consensus methodology, the changing load and loss study conditions, revenue requirement variations and other inputs from one test year to the next can be expected to shift calculated cost responsibilities among customer classes.[10] More importantly, concerns about revenue stability, customer impact and acceptance and other public policy considerations argue for using CCOS study results as a guide rather than a mandate.

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[9] See CA-T-5, pages 34 and 35.

[10] The Class Load Study supporting the CCOS cost allocations performed in this Docket were conducted in 2003, according to HECO T-22 at page 18. HECO is presently conducting an updated Class Load Study that can be used in its next rate case.

Q. SO FAR IN THIS DISCUSSION, YOU HAVE DESCRIBED CCOS AND REVENUE INCREASE DISTRIBUTION POSITIONS TAKEN BY HECO AND THE CONSUMER ADVOCATE. HOW DID THE DEPARTMENT OF DEFENSE ("DOD") ADDRESS THESE ISSUES?

A. In his Direct Testimony, the witness for the DOD, Mr. Brubaker, was advocating against any consideration of the CCOS study approach used by the Consumer Advocate that utilized the 100 percent demand classification of distribution network costs.[11] In addition, Mr. Brubaker was pushing for more substantial movement toward indicated cost of service, removing what he called "subsidies" by imposing much higher than average rate increases on Schedule R residential and Schedule F lighting customers to "fund" lower percentage increases for large commercial Schedule DS and Schedule P customers.[12] Ultimately, Mr. Brubaker did not specify a precise allocation of the revenue increase based upon the CCOS, but concluded at page 21 of his testimony with the statement, "I recommend that the Commission direct HECO to implement any approved rate increase by allocating the revenue increase among customer classes with the objective of reducing the existing interclass subsidies. Increases for various degrees of movement toward cost of service

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[11] DOD-300, pages 11-15.

[12] Id. Pages 19-21 and DOD-306 through DOD-308.

at HECO's requested revenue requirement are shown on Exhibits DOD-306 through DOD-308."

Q. HAS THE COMMISSION PREVIOUSLY INDICATED A PREFERENCE FOR ADHERENCE TO CCOS RESULTS IN RATE CASES?

A. Yes. The Commission has considered CCOS information in several prior rate cases, employing CCOS results but adopting a policy of gradualism in moving toward indicated cost of service by customer class. For example in Amended Decision and Order No. 16922 in MECO Docket No. 97-0346, the Commission concluded its discussion of CCOS issues and results with the statement:

> Upon review of the parties' proposals and evidence on revenue allocation, the commission concludes that MECO's proposed revenue allocation among the customer classes, including methodology, are reasonable. MECO's proposed revenue allocation among customer classes is in accord with its long-term objective of gradually reducing the subsidies among rate classes, and with the principles of fairness and nondiscriminatory allocation of the revenue requirements among the various customer classes. (D&O dated April 6, 1999 at 60).

Similar language can be found in Decision and Order No. 11893 in HELCO Docket No. 6999:

> We agree with HELCO that moving to equal rates of return for all rate classes in this docket will result in disproportionate rate increases for some rate classes. Thus, we conclude that HELCO's approach, methodology, and proposed revenue allocation in this docket are reasonable. They are in accord with HELCO' s long-term objective and with the principles of fairness and nondiscriminatory

allocation of the revenue requirement to the various customer classes. (D&O dated October 2, 1992 at 102)

Q. WHAT PROCESS WAS EMPLOYED IN NEGOTIATING THE REVENUE INCREASE PERCENTAGES THAT ARE SET FORTH IN THE STIPULATED SETTLEMENT LETTER?

A. As the approximate size of the overall revenue increase from settlement discussions between HECO, the Consumer Advocate and DOD became known, the parties engaged in discussions attempting to narrow the differences between the "equal percentage" revenue increase distribution proposals of HECO and the Consumer Advocate and the "removal of subsidies" position being advanced by the DOD. I prepared a Schedule as set forth in CA-S-500, to use as a tool to facilitate negotiations. This form of spreadsheet was iterated with alternative "Settlement Allocation Percentage" values in column (I) for the New Rate Structure to evaluate alternative rate increase distributions.

Q. WHAT COST OF SERVICE INFORMATION WAS USED IN COLUMNS A THROUGH G OF EXHIBIT CA-S-500?

A. The CCOS results shown in CA-S-500 in columns A through G were taken directly from the HECO Update evidence prepared by Mr. Young that was included in HECO Update T-22, Attachment 1, at page 2. These values show the currently effective revenues, the estimated class Rate of Return percentages and the corresponding "ROR Index" that was calculated by HECO for each rate schedule, under both the "Using Minimum System" and the "Treating Distribution Network 100% Demand" approaches to cost allocation.

Q. DO COST OF SERVICE STUDY RESULTS PROVIDE ANY INDICATION OF HOW REVENUE INCREASES SHOULD BE DISTRIBUTED, IF MOVEMENT TOWARD INDICATED COST OF SERVICE IS DESIRED?

A. Yes. It is notable that, under both CCOS approaches presented by HECO in this Docket, the same pattern of ROR disparity exists – with Schedules R, J and F earning below average rates of return and Schedules G, DS and P earning above average rates of return at current revenue levels. This result suggests a need for somewhat higher than average revenue increases for Schedules R, J and F with lower than average increases to the other schedules, if movement in the direction of indicated cost of service is desired.

Q. WHAT ARE THE PERCENTAGE VALUES THAT APPEAR AT COLUMN H WITHIN CA-S-500, THAT ARE CAPTIONED "DISTRIBUTION AT EQUAL REVENUE %"?

A. These are the rate increase distribution percentages that would be applicable if the Commission wanted to implement the equal percentage distribution of the revenue increase. These percentages are derived mathematically from the Sales Revenues at current effective rates in the first column of the Exhibit. The amounts are shown under the newly proposed HECO New Rate Structure at lines 1 through 7, with corresponding calculations under the Existing Rate Structure at lines 8 through 16.[13]

Q. WHAT IS DEPICTED IN COLUMNS (I), (J) AND (K) OF CA-S-500?

A. These amounts illustrate, for a hypothetical $70 million HECO rate increase, how the Settlement Allocation Percentages in column (I) that are based upon the Stipulated Settlement Letter at Exhibit 1, pages 84-85 would impact each rate schedule, yielding the dollar amounts in column (J) and the percentage revenue change values shown in column (K).

Q. HOW CAN THE COMMISSION EVALUATE THE EQUAL REVENUE DISTRIBUTION PERCENTAGES COLUMN (H) AND THE NEGOTIATED SETTLEMENT ALLOCATION PERCENTAGES IN COLUMN (I)?

A. The calculations I used to support the negotiations are depicted in columns (K) and (L) of CA-S-500. If we observe in column (K) at line 7 that a $70 million hypothetical revenue increase represents an overall 3.8 percent increase, then

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13 Pursuant to the Settlement Agreement in Docket No. 2006-0386, HECO's test year 2007 rate case, the Company agreed to design a separate rate class for customers who are directly served from a dedicated substation and to eliminate Schedule H in the rate design proposed in this case. These changes are described in HECO T-22 at pages 23 and 33-36.

the comparable effective percentage increases under the settlement for each rate class can be observed at lines 1 through 6 of column (K). To aid in the comparison, I added column (L) which calculates a ratio of the class increases to the total overall increase of 3.8 percent. The results can be summarized by first noting that each of the rate classes with below average returns (in columns C and F) are being allocated a revenue increase that is above average (as shown in columns K and L). The rate classes shown to be earning above average returns under currently effective rates (again in columns C and F) receive lower than average revenue increase percentages (as shown in columns K and L). In an effort to balance a gradual movement toward indicated cost of service, while mitigating any abrupt changes to any particular rate schedule, all of the proposed increases for the rate schedules fall within a band ranging from 51 percent to 125 percent of the average overall increase.

Q. HOW DOES THE STIPULATED ARRAY OF REVENUE INCREASES AMONG CUSTOMER CLASSES IN COLUMNS (I) THROUGH (L) OF CA-S-500 COMPARE WITH THE REQUIRED INCREASE DISTRIBUTIONS SET FORTH IN MR. BRUBAKER'S EXHIBITS DOD-306 THROUGH DOD-308?

A. The greatest disparity in the required revenue increase percentages shown by Mr. Brubaker can be observed at DOD-306, where revenue increases required to "Reduce Subsidies by 100%" would require a residential Schedule R revenue increase of 11.36 percent, compared to a Schedule DS revenue increase of only 1.63 percent. I have summarized the amounts of required increase percentages shown by Mr. Brubaker for Schedules R and DS for each of his 100%, 50% and 25% subsidy reduction scenarios in the table below, with the final row of the table depicting the Stipulated Settlement Letter provisions for Schedules R and DS:

		Rate Increase Percentage and Ratios				
DOD Scenarios		Sched R	Sched DS	Avg %	Ratio R	Ratio DS
DOD-306	Subsidy Reduce 100%	11.36%	1.63%	5.36%	2.12	0.30
DOD-307	Subsidy Reduce 50%	9.19%	2.41%	5.36%	1.71	0.45
DOD-308	Subsidy Reduce 25%	8.11%	2.80%	5.36%	1.51	0.52
Settlement Agreement		4.46%	1.90%	3.76%	1.19	0.51

This table shows that the Stipulated revenue increase distribution achieves a Schedule DS rate increase consistent with the 25 percent reduction of "subsidy" for Schedule DS that was targeted by Mr. Brubaker on Exhibit DOD-308, since Schedule DS is assigned in the Stipulation a revenue increase at 51 percent of the system average increase. However, this is accomplished in the Stipulation without exposing Schedule R residential ratepayers to the excessive revenue increases that were suggested in Mr. Brubaker's Exhibits DOD-306 through DOD-308. In fact, the Stipulation does not increase any rate Schedule's revenues by more than 125 percent of the average overall rate increase ultimately approved by the Commission.

Q. ARE THERE ANY SPECIFIC COST ALLOCATIONS OR WORKPAPERS SUPPORTIVE OF THE REVENUE INCREASE PERCENTAGE AMOUNTS THAT WERE NEGOTIATED BY THE PARTIES IN THIS DOCKET?

A. I am not aware of any underlying calculations beyond the form of analysis set forth in CA-S-500, which was presented in scenarios by the Consumer Advocate and discussed with representatives for HECO and the DOD. Settlement upon the revenue increase percentages set forth in the Stipulated Settlement Letter was based upon the informed judgment of the parties.

III. <u>RATE INCREASE IMPLEMENTATION.</u>

Q. THE INTERIM DECISION AND ORDER AT PAGE 15 STATES, "ON PAGES 20 AND 21 OF HECO T-1, HECO PROPOSED TO ALLOCATE COST INCREASES EQUALLY TO ALL CUSTOMER CLASSES ON A PER-KWH BASIS." IS THIS A CORRECT STATEMENT?

A. The statement was accurate with respect to HECO's referenced Direct Testimony. However, in the Stipulated Settlement, HECO has agreed to forego the step increase associated that was initially proposed to occur upon completion and operation of its new Campbell Industrial Park CT-1 unit. Additionally, as part of its submission of Revised Schedules Resulting from Interim Decision and Order on July 8, 2009, HECO has modified its proposed form of implementation of the general interim rate increase in this Docket. The revised interim increase would be applied on a percentage of base charges approach instead of a per-KWH approach.[14]

Q. DOES THE ELIMINATION OF THE CT-1 STEP INCREASE AND HECO'S RECENT MODIFICATION OF THE INTERIM RATE PROPOSAL TO A PERCENTAGE SURCHARGE BASIS APROPRIATELY RESPOND TO THE COMMISSION'S CONCERN STATED AT PAGE 16 OF THE ID&O REGARDING HOW RATE INCREASES IMPLEMENTED ON A CENTS-PER-KWH BASIS "...COULD INAPPROPRIATELY INCLUDE FIXED COSTS IN THE VARIABLE COMPONENT OF RATES"?

A. The changes made by HECO will preserve the existing mix of fixed and variable charges to customers under each rate schedule. Applying the interim increase as a percentage surcharge on the customers' bills will retain and uniformly increase the monthly fixed customer charges and variable monthly demand and energy charges on each bill during the period interim rates are effective.

Additionally, as a matter of clarification, I would note that the recovery of substantial amounts of utility fixed costs through variable components of rates, such as through energy or demand charges, is a common ratemaking

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14 See HECO Revised Schedules Resulting from Interim Decision and Order dated July 8, 2009 at Exhibits 2 and 2A.

outcome. In fact, the inclusion of fixed costs in the variable component of rates can be used as a means to amplify pricing signals that might encourage conservation. *However, revenue stability concerns can emerge if excessive amounts of utility fixed costs are recovered through variable rate elements,* because the utility's opportunity to fully recover its fixed costs could be diminished in times of fluctuating or declining sales.

Q. DOES THIS CONCLUDE YOUR TESTIMONY ON COST OF SERVICE AND RATE DESIGN MATTERS?

A. Yes.

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2008-0083, TEST-YEAR 2009
SUMMARY OF CLASS REVENUE REQUIREMENTS AND CLASS RATES OF RETURN
AT CURRENT EFFECTIVE RATES

NEW RATE STRUCTURE

Line No.	Rate Class	Cost of Service Using Minimum System Study			COS Treating Distribution Network 100% Demand			Settlement Agreement Final Increase Percentage Development				
		Sales Revenues ($000s)	Rate of Return (%)	ROR Index (%)	Sales Revenues ($000s)	Rate of Return (%)	ROR Index (%)	Distribution At Equal Revenue %	Settlement Allocation Percentage	Illustrative $70 million Increase	Effective Percentage Increase	Ratio of Average Increase
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
1	Schedule R	$560,709.1	2.42%	49.84%	$560,709.1	3.97%	81.70%	30.12%	**35.74%**	$25,017.9	4.5%	119%
2	Schedule G	$111,242.0	8.23%	169.25%	$111,242.0	13.77%	283.22%	5.98%	**4.48%**	$3,136.9	2.8%	75%
3	Schedule J	$509,668.3	4.58%	94.10%	$509,668.3	2.82%	58.04%	27.38%	**34.22%**	$23,953.8	4.7%	125%
4	Schedule DS	$260,144.9	6.79%	139.55%	$260,145.0	6.79%	139.55%	13.97%	**7.06%**	$4,942.0	1.9%	51%
5	Schedule P	$410,467.1	8.69%	178.63%	$410,467.0	6.27%	128.92%	22.05%	**17.86%**	$12,502.0	3.0%	81%
6	Schedule F	$9,519.2	2.79%	57.38%	$9,519.2	1.42%	29.27%	0.51%	**0.64%**	$447.4	4.7%	125%
7	Total Sales Revenues	$1,861,750.6	4.86%		$1,861,750.6	4.86%		100.00%	**100%**	$70,000.0	3.8%	100%

SOURCE: ALL AMOUNTS ABOVE TAKEN FROM HECO RATE CASE UPDATE - HECO T-22, ATT. 1, P.2 OF 39

EXISTING RATE STRUCTURE

Line No.	Rate Class	Sales Revenues ($000s)	Settlement Agreement Interim Increase Percentage Development				
			Distribution At Equal Revenue %	Settlement Allocation Percentage	Illustrative $70 million Increase	Effective Percentage Increase	Ratio of Average Increase
8	Schedule R	$560,709.1	30.12%	**35.74%**	$25,017.9	4.5%	119%
9	Schedule G	$108,392.5	5.82%	**4.37%**	$3,056.6	2.8%	75%
10	Schedule H	$8,181.6	0.44%	**0.55%**	$384.5	4.7%	125%
11	Schedule J	$504,336.3	27.09%	**33.86%**	$23,703.2	4.7%	125%
12	Schedule PS	$201,461.8	10.82%	**8.64%**	$6,051.2	3.0%	80%
13	Schedule PP	$431,097.1	23.16%	**15.17%**	$10,618.2	2.5%	66%
14	Schedule PT	$38,053.1	2.04%	**1.03%**	$721.0	1.9%	50%
15	Schedule F	$9,519.2	0.51%	**0.64%**	$447.4	4.7%	125%
16	Total Sales Revenues	$1,861,750.7	100.00%	**100%**	$70,000.0	3.8%	

CA-S-500
Docket No. 2008-0083

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing **DIVISION OF CONSUMER ADVOCACY'S SUPPLEMENTAL TESTIMONIES AND EXHIBITS** was duly served upon the following parties, by personal service, hand delivery, and/or U.S. mail, postage prepaid, and properly addressed pursuant to HAR § 6-61-21(d).

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DATED: Honolulu, Hawaii, July 20, 2009.

Desiree Lopat
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